

PETROLEUM DEVELOPMENT AND TECHNOLOGY

1946

PETROLEUM DIVISION

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TRANSACTIONS

OF THE

AMERICAN INSTITUTE OF MINING AND METALLURGICAL ENGINEERS

(INCORPORATED)

and Petroleum

Volume 165

PETROLEUM DEVELOPMENT AND TECHNOLOGY 1946

PETROLEUM DIVISION

PAPERS AND DISCUSSIONS PRESENTED BEFORE THE DIVISION AT MEETINGS HELD AT
TULSA, OCT. 8, 1945; HOUSTON, OCT. 10, 1945; FORT WORTH, OCT. 12-13, 1945;
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Left, Prof. Karpinski

FOREWORD

These TRANSACTIONS are a permanent record of one phase of activity of the Petroleum Division of the A.I.M.E. for 1945. The presentation covers technical papers on petroleum research and production engineering, but does not include the production review, as has been the custom in the past. The statistical reports of production will appear as a separate volume, to be called "Statistics of Oil and Gas Development and Production." ✓

The authors and division committeemen to whom we are indebted for these works have accomplished notable success in their efforts during difficult times. General confusion associated with the war was not conducive to the concentrated thought necessary to arrive at and present advanced technology. The moving of essential employees into the armed services and other war assignments so increased the responsibilities of the majority of our members that it was a burden for them to give time to the preparation of papers for publication by the Institute.

10/52
Meetings during the year for the presentation of these papers followed a different pattern because of difficult travel conditions. The regular annual meeting usually held in New York was canceled in 1945. Our Division held technical sessions in the fall at Tulsa, Oklahoma; Fort Worth, Texas; Houston, Texas, and Los Angeles, California, and in this manner served a maximum number of members with the minimum travel and hotel requirement.

The papers presented are evenly balanced between Research and Production Engineering. There are no papers covering Economics, principally because of the cancellation of the New York meeting, at which these papers are usually presented.

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In 1936 the Institute established the Anthony F. Lucas Gold Medal, to be awarded from time to time "for distinguished achievement in improving the technique and practice of finding and producing petroleum." These awards are sponsored by the Petroleum Division.

Captain Lucas was a pioneer in the oil industry, one of the early wildcatters and a leading mining and petroleum engineer. He was famous as the discoverer of Spindletop. He became a member of the Institute in 1895 and in 1913 was the first Chairman of the Petroleum and Gas Committee of the Institute, the forerunner of the present Petroleum Division. He also headed the Committee in 1914, 1917 and 1918.

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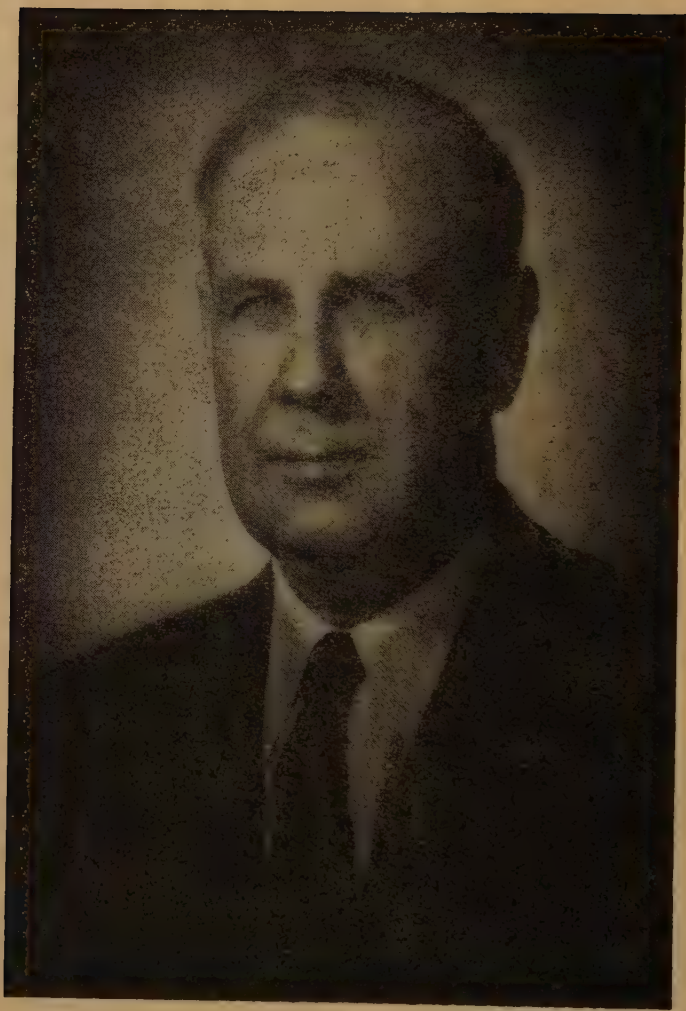
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"For his pioneer work in laying the foundations of Petroleum Engineering through early recognition and lucid exposition of the energy relationships in petroleum reservoirs. For his vision and leadership in developing secondary recovery methods and his large influence in the general improvement of petroleum production practices."

Chapter I. Research

The Electrolytic Model and Its Application to the Study of Recovery Problems

By HOLBROOK G. BOTSET, * MEMBER A.I.M.E.

(Tulsa, Fort Worth, Houston and Los Angeles Meetings, October 1945)

ABSTRACT

It is possible by means of the electrolytic model to simulate water-flooding or gas recycling systems involving input and output wells, and also the encroachment of a natural water drive. The results are obtained pictorially, and by simple measurements and calculations the percentage of recovery is obtained qualitatively as a function of the total input.

INTRODUCTION

The increased demand for petroleum products, together with the decline in discovery rate and the higher cost of recovery as deeper formations are brought into production, has stimulated interest in methods for studying and predicting efficiencies of various production programs. Among methods of recovery that have become of increased significance recently are gas recycling in condensate fields and secondary recovery by water-flooding. The electrolytic model is a useful device for studying such methods in the laboratory, at least in a qualitative way.

The original experiments with electrolytic models and the development of their application to the study of secondary recovery problems were published in 1933.^{1,2,3} Subsequently other investigators continued the development and modification of the basic method, with resultant improvements and extension of its applications.⁴⁻⁷

Manuscript received at the office of the Institute June 13, 1945. Issued as T.P. 1945 in PETROLEUM TECHNOLOGY, November 1945.

* Gulf Research and Development Co., Pittsburgh, Pennsylvania.

¹ References are at the end of the paper.

The method and equipment to be described here are thought to represent still further improvement in the results obtainable, with increased validity in their application to field problems.

SUMMARY OF PRINCIPLES OF OPERATION

The underlying theory of the operation of the model is given in references 1, 2 and 3. However, a brief statement of principles involved is given herewith. The applicability of the model is based on the fact that Ohm's law and d'Arcy's law are exactly analogous; whence, electrical flow through a conducting medium may be used to simulate homogeneous fluid flow through a permeable medium. If two electrodes are placed in a conducting (ionized) solution and connected to the positive and negative terminals of a source of direct current, the positive ions of the solution will move toward the negative terminal. Since the velocity of an ion in an electrolytic medium is proportional to the electrical gradient, just as the velocity of a fluid particle in a porous medium is proportional to the pressure gradient, the motion of the ions in the potential field will be the same as the motion of fluid particles in a porous medium if the positive and negative terminals (input and output wells) and boundary conditions are made equivalent in shape and distribution.

In order for the analogy to hold exactly, the sand must be assumed to have uniform porosity and permeability and the input

and output fluids to have identical viscosities and densities. In gas recycling in condensate fields and in water-flooding in oil fields, the variations in density and

THE APPARATUS

The model equipment consists essentially of a transforming-rectifying system for converting 110 volts of alternating current

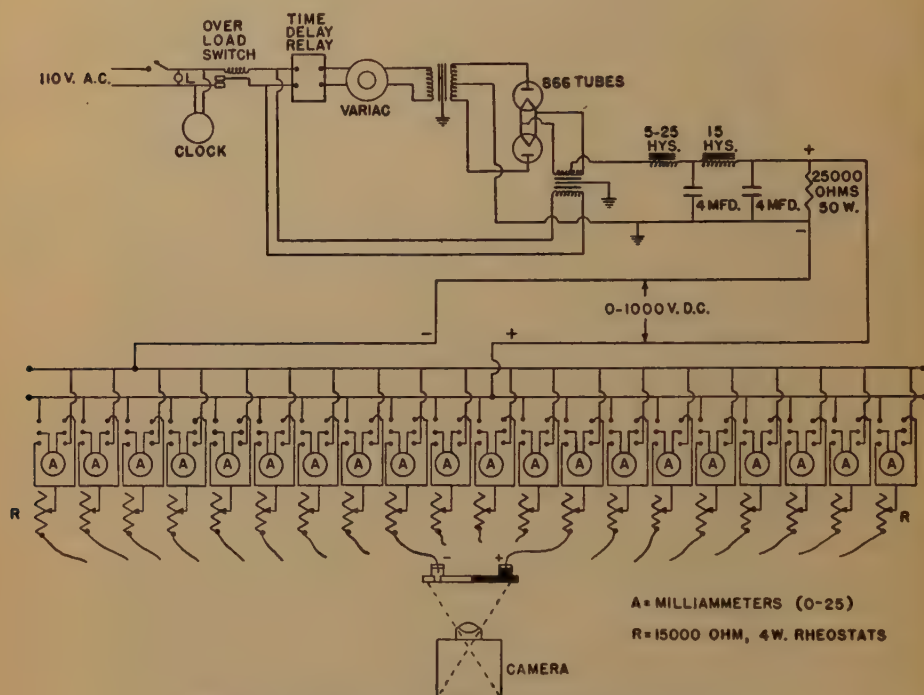


FIG. 1.—ELECTRICAL CIRCUIT FOR ELECTROLYTIC MODEL.

viscosity usually are not great enough to introduce serious discrepancies into the results.

In using the motion of ions to represent fluid flow in a sand, it is necessary, of course, to have the ions visible so that their motion may be observed. For this purpose, copper-ammonium ions, which are deep blue in color, are used to represent the input fluid, while the sand is represented by an agar gelatin solution containing colorless zinc-ammonium ions. These zinc-ammonium ions, which represent the fluid to be produced from the sand, have the same mobility as the copper-ammonium ions, so that the two ions represent two fluids of equal viscosity.

to any desired voltage of direct current up to 1000 volts. The electrical circuit is shown semidiagrammatically in Fig. 1, and a photograph of the apparatus in Fig. 2. The d.c. output voltage (0-1000) is regulated by means of the Variac, which controls the primary voltage of the transformer. The capacities and inductances are for the purpose of evening out the ripples in the full-wave rectified a.c. The overload switch opens the main circuit in case of accidental short or other high current demand. A clock that measures elapsed time (upper center of the panel, Fig. 2) is placed in the primary circuit as a means of easily keeping track of the time schedule of the flood.

Provision is made for 20 wells, each with its own milliammeter and each, controlled by a switch and a 20,000-ohm rheostat. The switch is a double-pole

on which the flood model rests is one foot square, thus limiting the size of the model.

The model of the field or area of interest consists of a transparent conducting layer

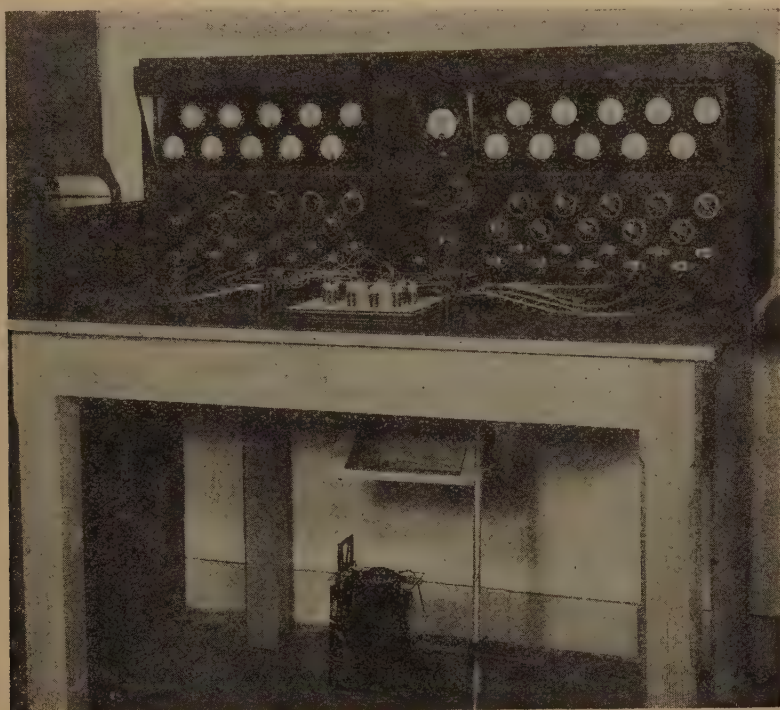


FIG. 2.—ELECTROLYTIC MODEL APPARATUS.

double-throw switch so arranged that each well may be connected to either the positive or the negative side of the circuit. The switch automatically reverses the ammeter connection as the well is reversed, so that the d.c. ammeter always reads properly.

The flood itself is set up on a glass plate in the center of the table (Fig. 2). Below the table is a mirror, offset and placed at an angle so that the operator may observe the progress of the flood, since the wells and cover plate on top of the model make it impossible to view the flood from above. The photographic record of the flood is made by the camera placed under the table directly below the glass plate. This plate

of 1 per cent agar gelatin solution containing 0.1 normal zinc-ammonium chloride. The wells, made of transparent plastic, are $\frac{1}{2}$ in. inside diameter and 1.5 in. long. The tips, which penetrate through the cover plate and into the gelatin field, are $\frac{3}{32}$ in. in diameter and are made with eight tiny slots, to facilitate current flow through the tip into the field. These slots practically eliminate the tendency of the tips to overheat and dry out. The wells rest on an opaque white bakelite cover through which the $\frac{3}{32}$ -in. diameter tips penetrate into the gelatin field.

The input (positive) wells are filled with a 0.1 molal deep blue copper-ammonium chloride solution containing 1.5 per cent

agar. The output (negative) wells contain the same solution as the field except that the agar concentration is 1.5 per cent. An electrode is placed in the upper part of each well, immersed in a small amount of the electrolyte solution, which is added to each well after the gelatin solution has set.

For many experiments a two-dimensional representation of the field or area of interest is used, consisting of a uniform thin ($\frac{1}{16}$ in.) gelatin layer made up of a 0.1 molal zinc-ammonium chloride solution containing 1 per cent agar. The desired shape of the field in the flood model is established by cutting a $\frac{1}{16}$ -in. thick sheet of plastic, such as Plexiglas or Lucite, into the shape of the field boundary, and sticking it onto a plate of glass by Duco cement. The gelatin solution is then poured into this area, which is carefully leveled before the solution is poured, to assure uniformity of thickness over the area. By proper precautions in preparing the solution and in pouring this field, it may be made perfectly transparent.

PREPARATION OF FIELD OF VARIABLE THICKNESS

Sometimes it is desirable to have a variable gelatin thickness to correspond to the variations in thickness, or better, available pore volume per unit area of the producing sand. In these cases the container for the gelatin must be made of transparent plastic cast to the desired shape. The technique of preparing these cast plastic bases involves a somewhat complicated procedure. The area to be used in the experiment is selected and an isopach (or isopore volume) map is prepared, preferably by the geological staff. The contours should be close enough for a good delineation of the thickness (pore volume) variations. The exact area or areas to be used in the model experiments is selected and outlined on the map. It is convenient to use a rectangular shape for this area, usually about 8 by 10 in. in size. The desired

area on the map is then laid off in $\frac{1}{2}$ in. squares, the vertical lines being numbered consecutively and the horizontal lines lettered. Tabulations are then made for each of the numbered and lettered lines, giving the thickness of the sand at each intersection. It is preferable that the maximum gelatin thickness in the model be $\frac{3}{32}$ in.; therefore figures for the maximum sand thickness (or pore volume) are retabulated in gelatin thickness. The thickness contour for each numbered and lettered line of the grid is then plotted on cross-section paper to a greatly enlarged scale, to reduce errors in plotting. A pantograph must then be used to reduce the contour back to the scale of the model, so the enlargement used in plotting the contours will depend upon the capacity of the pantograph. It is convenient, if possible, to use a scale factor of about six to one in plotting the curves. In the reduction to scale by the pantograph a metal stylus is used and the contour is scribed directly onto a piece of brass $\frac{1}{16}$ in. thick. The brass is cut into a strip approximately $\frac{1}{2}$ in. wide, measured from a standard base, and the contour edge is hand-filed down to the scribed line. When all the numbered and lettered lines have thus been transferred to brass strips, these are fitted together by lap joints so that the bottom surface is a plane and the top surface has the contour of the thickness variation of the sand. In this construction the entire thickness variation of the sand is taken up in the one surface, since the top gelatin surface in the model is flat.

The brass grid is then set into a rectangular brass container that has removable sides $\frac{1}{4}$ in. higher than the highest point on the grid. The openings between the grids are filled with an excess of plaster of paris, which, after setting, is carefully sanded down so as just to expose the top edges of the brass grid. A negative casting of this surface is then made using a hard dental plaster, and from this negative casting a transparent plastic casting is made, using

the technique followed in making plastic dentures. The inner surface of this transparent plastic container corresponds to the thickness variation in the producing sand. This container is then filled with the conducting gelatin solution, to represent the field in the model experiments.

The well locations are drilled into the cover plate with relative spacings the same as for the field under consideration. The scale of the model should be chosen so that the distance between wells in the model is in general between $\frac{5}{8}$ and $1\frac{1}{2}$ in. With this spacing and a maximum gelatin thickness of $\frac{3}{32}$ in., one complete flooding experiment can be run in from 3 to 6 hr. Lease lines and contour lines may be drawn on the bottom of the bakelite plate, so that they will be photographed together with the flood pattern. Of course, in an experiment using a variable gelatin thickness, the cover plate must be accurately positioned on the gelatin container. This position, once established, may be secured by means of small metal pins set into the corners of the plastic base and fitting into holes drilled in the cover plate.

OPERATION OF THE MODEL

After the wells have been filled and placed in position, and the electrodes have been properly connected, the current is turned on and the flow through the various injection and producing wells is adjusted to correspond to the relative injection or production rates used in the field. Photographs of the flood are taken at suitable time intervals. In the adjustment of the relative rates through the wells, the groups of injection and producing wells, are considered separately, because in field operation, owing to the compressibility of the system, the total production from the field may be greater or less than the total injection into the field, while in the electrolytic model the input current must always equal the output current. As an example, assume that there are 10 injection wells in

a field and that to attain the desired flood pattern a current of 10 ma. each flows into five of the wells and 5 ma. each into the other five. This makes a total current of 75 ma. If the gas-injection system in the field is capable of handling 60,000 Mcf. per day, each milliamper in the injection wells would then correspond to $60,000/75$ or 800 Mcf., so that the injection rate into the wells taking 10 ma. would be 8000 Mcf. per day and 4000 Mcf. into those taking 5 ma. Similarly, in this same experiment there might be seven producing wells, four with a current of 15 ma. and three with 5 ma., each making a total output current of 75 ma. If the production from this field were 75,000 Mcf. per day, each milliamper in the producing wells would then correspond to 1000 Mcf. of produced gas per day.

In the example first cited, the number of cubic feet per ampere for the injection wells is less than that for the producing wells. This discrepancy occurs because the actual system is compressible while the electrical system is "incompressible." In practice, of course, the production rate for a field frequently exceeds the injection rate, causing a gradual decline in over-all field pressure. This unbalance of production vs. injection cannot be simulated in the electrolytic model, but negligible error is introduced by regarding the producing and injection wells as unit groups and determining the production and injection rates in the manner just described. Frequently it is desirable to know the time scale of the model. This may be determined in the following manner. A photograph of the flood is taken after the flood pattern has covered an appreciable area, but before it has reached any output wells. The area of the flood around a given well is planimeted and converted into acres covered. Knowing the thickness of the sand, its porosity and connate water content, the pore volume swept out by the flood at this stage may be determined. This volume is

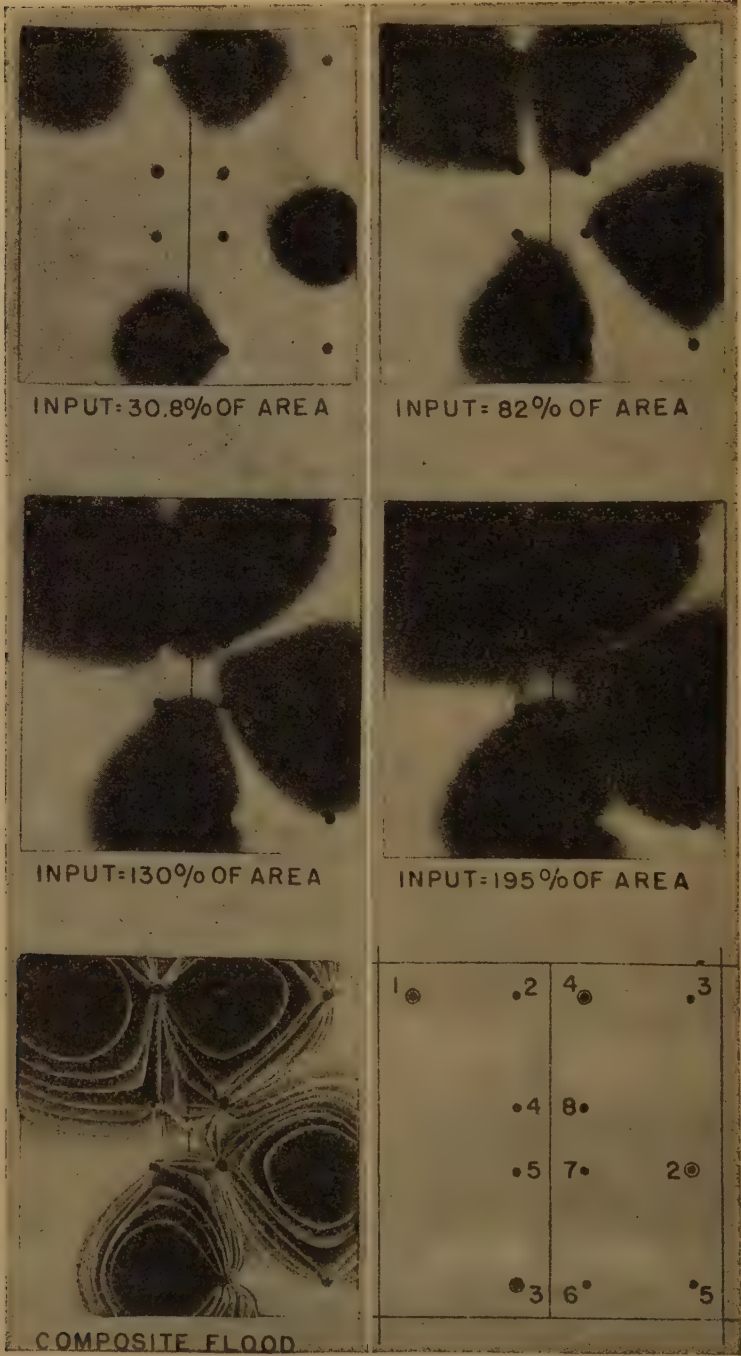


FIG. 3.—AN EXPERIMENTAL FLOOD PATTERN.

at the pressure and temperature of the reservoir. The total volume injected into the well in question divided by the daily injection rate will give the number of days

The curves of Fig. 4 are obtained by planimetering each of the flood patterns shown in the composite picture in Fig. 3. The area of each flood stage is expressed as

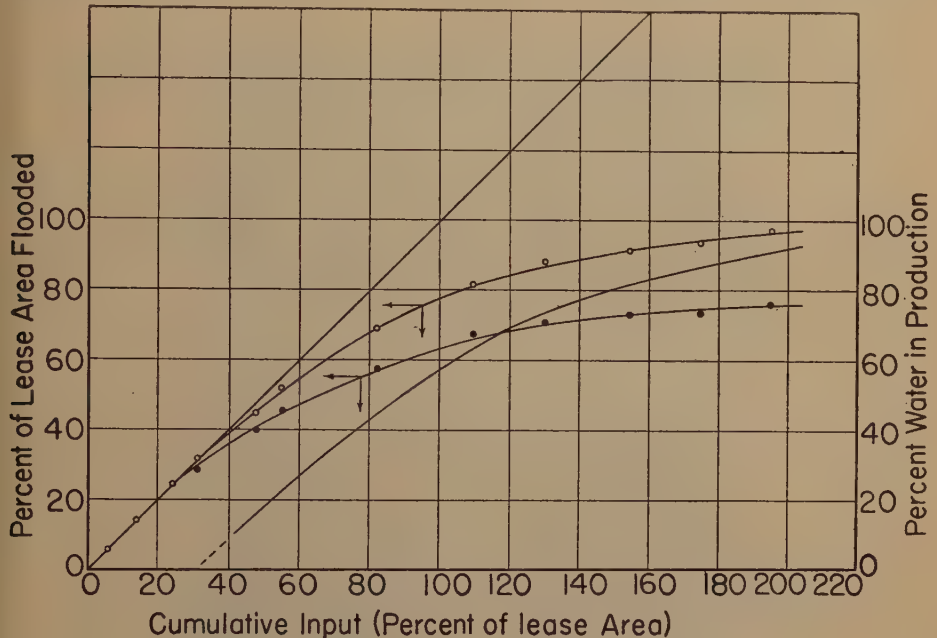


FIG. 4.—CURVES DERIVED FROM THE FLOOD PATTERNS OF FIGURE 3.

required to obtain the pattern as measured. This length of time then corresponds to the elapsed time required to obtain this pattern in the model. If this is done in two or three wells, or at two or three intervals for one well, and averaged, a more accurate time scale may be established. Of course, this procedure may be followed only if the flow rates are maintained constant, which is the customary procedure in the model studies.

The pictorial results obtained in a flood experiment, together with curves derivable from these pictures, are shown in Figs. 3 and 4. In Fig 3, four individual photographs of typical stages of the flood are shown together with a composite picture in which were superposed all the photographs taken of the flood, in order to give a better idea of the manner in which the flood advanced.

a fraction of the area of interest and this value is plotted as a function of the corresponding total input, also expressed as fraction of the area of interest. The abscissas for the points of the curve are determined by planimetering the photographs taken before the input fluid reaches any output well, dividing this area by the total time elapsed, and averaging the results for the photographs measured. This averaged value is then multiplied by the elapsed time for each photograph throughout the experiment and expressed as a fraction of the area of interest. The points obtained before input fluid reaches any output well should lie on a straight line through the origin. This line, projected throughout the flood, represents the total cumulative input at any time. The extent to which the actual flood curve drops below this straight line

represents the amount of input fluid being withdrawn through the producing wells, assuming that total output equals total input. A qualitative indication of the per-

is the upper one, with open circles, which represents the total area flooded expressed as percentage of the lease area. The lower curve (solid dots) in Fig. 4 represents the

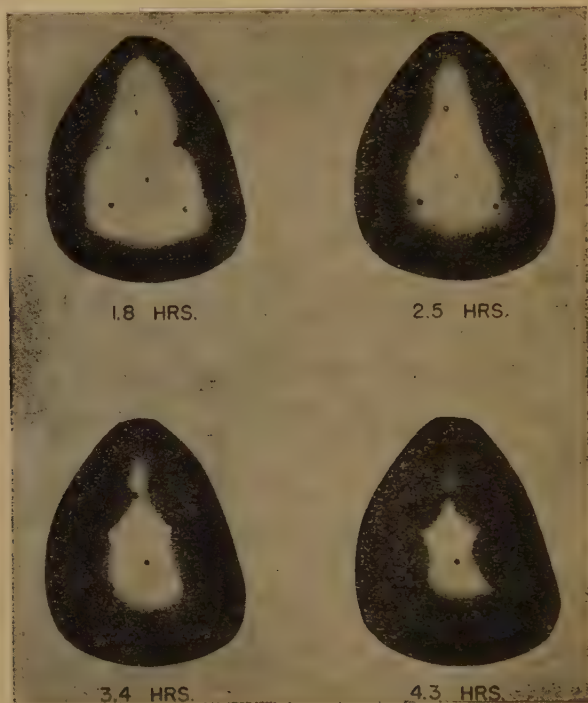


FIG. 5.—EDGE-WATER ENCROACHMENT EXPERIMENT.

centage of input fluid in the production may be obtained by taking the difference between the increment in total input fluid and the increase in flooded area for definite intervals.

The area of interest in this flooding experiment is the lease area, hence input and output are expressed in terms of this area. The photographs in Fig. 3 show only the lease area, although in the experiment a considerably larger area was utilized. It was necessary to use this larger area in order to get the proper pressure distribution in the lease area; therefore, in determining the ratio of input to output fluid, it is necessary to measure the total input, whether or not it is within the lease boundary. The curve in Fig. 4 resulting from this measurement

actual percentage of the lease area flooded. The upper curve is used in determining the fraction of input fluid (water in this case) in production. Since the curve showing the percentage of water in the production represents differences between the other two curves, and these differences are read from the plotted curves, the derived curve is qualitative only, but it should be of some value as a general indication of the degree of contamination of production by input fluid.

It is also possible, by the use of what might be called an "input trough," to simulate the encroachment of edge water into a field during production. The input trough, which consists essentially of serrated plastic strips set into grooves cut

into the bakelite cover plate, is placed along the initial water-oil contact line. As the current flows, the copper-ammonium ions flow through the serrations in the plastic strips into the field. Fig. 5 shows some photographs of an experiment using this technique.

LIMITATIONS OF THE ELECTROLYTIC MODEL

As is apparent from the foregoing discussion, one of the limitations of the model is the fact that the system must be regarded as incompressible—production must always be accompanied by equal injection, and vice versa; because the model is purely a resisting medium and all current that flows in must simultaneously flow out. This limitation is comparatively insignificant, however, and is generally ignored in the interpretation of model results.

Another limitation that should always be borne in mind when considering applications of electrolytic model studies is that of viscosity relations between input and output fluids. The flood pattern as obtained in the model is that which would result if the viscosities and densities of the input and output fluids were equal. This seldom, if ever, occurs in practice, and the more divergent these properties are, the less applicable the model results. It is for this reason, for example, that the electrolytic model may not be used to study the spread of a gas cap into an oil zone under pressure maintenance; the viscosity and density differences between the oil and gas are too great to permit application of the flooding picture that would be obtained by a model experiment.

Probably the most serious limitation of the model experiments is the fact that the permeability in the field must be assumed to be uniform. So far no satisfactory method has been developed to introduce local horizontal permeability variations into the model experiments. Of course, if the permeability varies stratigraphically

and yet is uniform in each stratum, a series of experiments could be made using each stratum separately and varying the thickness of each inversely as its permeability. If the same current were used for each stratum, the relative flooding times could thus be determined.

In applying the results of the model experiments, therefore, it is necessary to make proper allowances for the distortions in the patterns that would be introduced by variations in permeability. In many cases permeability variations are slight enough to introduce no significant error, in others they may not be well enough known from well logs to permit simulation in the model if such were possible. Hence, the uniform permeability of the model is not generally thought to be sufficiently in error to impair seriously the validity of the results obtained.

Certain other factors are sometimes regarded as placing definite limitations on the application of the model—such factors as diffusion, variation in ion transference with current density and with salt concentration and variation of conductivity with current density. A fairly extensive discussion of these conditions, both pro and con, will be found in reference 7. Our experience with the model experiments indicates that any errors resulting from such factors are of limited magnitude and that the results obtained with the model under properly stipulated conditions may generally be regarded as semiquantitative.

CONCLUSIONS

The electrolytic-model method for studying recoveries obtainable by water-flooding or gas recycling in condensate fields, gives moderately accurate results in a very short time. By this means it is possible to obtain in a few days, and at a negligible cost, qualitative comparison of the effect on recovery, of variation in the distribution and rates of operation of input and output

wells in a given field. Edge-water encroachment into a field may also be studied by this method.

It is realized, of course, that the results from these model experiments represent highly idealized conditions practically never found in actual field operations. However, the pictures obtained in these experiments on a given field, when considered in conjunction with the variations in porosity, permeability, sand thickness, etc., afford information obtainable in no other way, and should help to provide a better estimate as to the proper operating technique.

ACKNOWLEDGMENTS

The author wished to acknowledge with gratitude the very extensive assistance of Mr. D. W. Reed in the construction of the equipment and in the development of the method of preparing a variable-thickness field. Thanks are also due Dr. Paul D. Foote, Vice-President of Gulf Research and Development Co., for permission to publish this paper.

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DISCUSSION

(G. H. Fisher presiding)

E. R. BROWNSCOMBE.*—Do you have any trouble with fading out?

H. G. BOTSET (author's reply).—No, we do not. Sometimes we have to change the output well when the zinc crystallizes out in the wells. Sometimes a well will fill up largely with the zinc extending into the field gelatin. We always have about 50 per cent extra wells on hand.

MEMBER.—Do you get the relative rate of the ampules? Would it not be considerably affected by the thickness?

H. G. BOTSET.—You must take that into consideration. Where there is variable thickness, use each little area of volume. It is a good deal of work to lay out a map and make the contours, and take the average thickness of the contours.

MEMBER.—Was this based on your total curve correlation with volume?

H. G. BOTSET.—Yes.

L. L. BAKER.†—What stop in the areas do you use—the farthest point?

H. G. BOTSET.—The diffuse region is about the thickness of a pencil line. I outline the flooded area with a hard pencil line. The slight depression this makes in the glossy photograph is then easily followed with the planimeter stylus.

E. R. BROWNSCOMBE.—Do you have any overheating at the electrodes?

H. G. BOTSET.—No, we do not. Sometimes when we take the plate off it is rather warm. We never put in more than 75 milliamperes total current.

MEMBER.—In changing, do you add and take off wells at various intervals, or do you have to change your connections?

H. G. BOTSET.—You simply replace the well in the hole already drilled.

MEMBER.—Has the operation of the model proved reliable as to field operations?

* Atlantic Refining Co., Dallas, Texas.

† Core Laboratories, Inc., Dallas, Texas.

H. G. BOTSET.—We have not had any history to check it by. We will know some time.

G. H. FISHER.*—When you have a set of input wells or output wells, can you vary the current to compensate for the permeability of the well? The capacity of input or output would be a measure of that.

H. G. BOTSET.—I doubt it very much.

MEMBER.—Would you care to make a statement as to the advantages of the electrolytic model as compared with other methods?

H. G. BOTSET.—It is speedy and cheap. You can get the whole pattern in three or four hours. It is complex and time consuming to plot all equipotential lines and gradients in the potentiometric model.

NORRIS JOHNSTON.†—The device described by Mr. Botset offers a very useful and practical method of studying the flow of fluids in a reservoir. Particularly is this true in the cases of edge-water encroachment and of either water or gas injection. The limitations Mr. Botset

has mentioned are rather serious, but they do not invalidate the qualitative results obtained. Very few oil reservoirs are truly uniform in sand permeability, but the inability of this type of electrolytic model to take account of variable permeability does not prevent the user from interpreting the results in a thoroughly useful manner. Similarly, reasonably safe corrections of the observed results may be made to account for oblique flow, and compressibility of reservoir fluids (net input or output other than zero). Oblique flow in reservoir sands, caused by either lenticularity or a variable permeability profile, produces so complex a flow pattern that its complete and detailed understanding is generally beyond the realm of reasonable expectation. The sweep effectiveness of a gas or water drive depends greatly on this complex flow pattern, but it is too much to expect of an electrolytic model to simulate reservoir variations when it is frequently not economically feasible to drill wells close enough together to determine the complete picture of permeability variations.

The presently described device will become obsolete only when most of the limitations are overcome in a single device that also retains the distinct advantages of versatility, simplicity, low cost, speed, and the ability to give a visual demonstration.

* Gulf Oil Corporation, Fort Worth, Texas.

† General Petroleum Corporation of California, Los Angeles, California.

Formaldehyde as an Inhibitor of Corrosion Caused by Hydrogen Sulphide

BY P. L. MENAUL* AND T. H. DUNN*

(Tulsa and Fort Worth Meetings, October 1945)

ABSTRACT

This paper discusses the results of an investigation made to develop a method of combatting corrosion of subsurface oil-well equipment caused by brines containing hydrogen sulphide. Carbon monoxide, aldehydes, and certain cyanide compounds were found by laboratory tests to effectively inhibit corrosion of steel by sulphide brines. Experiments were made for one year in eight wells in West Texas fields using formaldehyde as an inhibitor. It was found that the inhibitor treatment successfully prevented the severe corrosion previously experienced in these wells, and effected important net savings in operating costs.

INTRODUCTION

Corrosion of oil-field equipment has long been a problem in areas producing sour crudes. These areas include the major fields of Arkansas, Western Kansas, West Texas and New Mexico. Corrosion in these fields is caused primarily by the chemical action of hydrogen sulphide in the presence of water and by electric currents entering the wells through flow lines. Hydrogen sulphide is noncorrosive to iron or steel in the absence of water but under the usual conditions prevailing in oil wells where more or less water is present, hydrogen sulphide is very corrosive. This type of corrosion occurs over the pH range below 9, which includes all natural oil-field brines. If air is present in addition to hydrogen sulphide and water, corrosion proceeds at an extremely rapid

rate. It was reported several years ago that a string of oil-well tubing was literally dissolved within 50 days where an air lift was used on a well producing considerable water and hydrogen sulphide. Air is generally absent in wells producing sour crude.

After hydrogen sulphide corrosion starts, it proceeds with increasing severity and its correction becomes progressively more difficult. This characteristic of sulphide corrosion has been attributed to the formation of galvanic couples between the iron and steel equipment on one hand and the products of corrosion on the other.¹

Severe corrosion of subsurface oil-well equipment leads to a multitude of troubles. In addition to destruction of costly equipment, producing sands often are damaged by flooding with water leaking through corroded casing; bad mechanical conditions may develop in a well due to obstructions caused by corroded equipment lost in the hole, or partly collapsed casing; pumping operations are interfered with, and severe emulsification problems may result from the homogenizing action of corroded balls and seats.²

A typical case of severe corrosion caused by hydrogen sulphide was reported in Howard County, Texas, where it was necessary to pull tubing once a week to repair leaks after the tubing had been in use for only one year. On one well in this area a string of tubing was pulled 11 times in 8 months; 11 joints of tubing being replaced because of leaks. In Ector

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* Stanolind Oil and Gas Co., Tulsa, Oklahoma.

¹ References are at the end of the paper.

County, Texas, pump rods began to fail after being in service only 36 days. Because of excessive corrosion of oil-well casing in Magnolia and certain other Arkansas fields, the Oil and Gas Commission of that state notified operators to take steps to guard against corrosion caused by hydrogen sulphide. It is probable that the increased operating costs caused by sulphide corrosion will be a major factor in the future economic development of many oil fields in West Texas and other areas subject to this type of corrosion.

METHODS OF PREVENTING CORROSION

For many years, generally unsuccessful attempts have been made to prevent or minimize corrosion caused by hydrogen sulphide. Most of these efforts have been made by manufacturers of oil-well equipment and have been directed toward development of alloys capable of withstanding sulphide corrosion.^{3,4} Some types of alloy-steel tubing have been tried but without complete success; the higher cost of such tubing failing in many cases to be justified by the somewhat longer length of service. Nickel-alloy pump rods were found to resist corrosion satisfactorily in a well in Howard County, Texas, but the high initial cost of such equipment cannot always be justified economically.

Various paints, including those of synthetic rubber base, have failed to protect metal from attack in field operation. The use of zinc electrodes in the form of sleeves cast on tubing, working barrel and tubing anchor, has failed to prevent sulphide corrosion⁵ of subsurface oil-well equipment. Galvanized equipment also has failed to withstand sulphide corrosion. Alkaline materials such as caustic soda, sodium silicate, alone or with tannin, have been used to some extent in neutralizing fluids at the bottoms of wells. These have shown some benefit in a few cases but in general when the oil-field brines are made sufficiently alkaline to

reduce corrosiveness of the fluid, objectionable precipitates of calcium and magnesium are formed.

LABORATORY INVESTIGATION OF INHIBITORS

In view of the general failure of preventative measures previously proposed and the seriousness of the sulphide corrosion problem, an investigation designed to develop an improved method of combatting this type of corrosion was undertaken some time ago at the Research Department Laboratory of the Stanolind Oil and Gas Company.

As the first phase of this investigation, information was developed on the effectiveness of sodium hydroxide and other alkaline materials in neutralizing corrosive brines. The results showed that the corrosiveness of a brine was not appreciably decreased until its alkalinity was raised above pH 9. Treating to this degree of alkalinity produced a flocculent precipitate of calcium and magnesium compounds which, in field operation, would form objectional scale on equipment. Experiments were made with cathodic protection as a means for decreasing sulphide corrosion. This method proved unsuccessful. Efforts finally were directed toward finding a chemical inhibitor of sulphide corrosion. A sulphide brine from North Cowden field, Ector County, Texas, was used in making the numerous laboratory trials of inhibitors. Its analysis was:

	P.P.M
Sodium.....	14,000
Calcium.....	1,600
Magnesium.....	500
Sulphate.....	3,000
Chlorine.....	26,000
Bicarbonate.....	1,000
Sulphide as H_2S	<u>1,000</u>
Total solids.....	46,100
pH value.....	6

When tested at the well head soon after sampling, various samples of brine from this field were found to be acidic, having a range of pH 4.5 to 6.8. When exposed to

the atmosphere for a short time, the pH value increased to above pH 7, owing to loss of some hydrogen sulphide and gradual decomposition of the portion remaining in the water. The gas produced in this field contains 0.5 per cent carbon dioxide and from 5 to 8 per cent hydrogen sulphide by volume.

In order to simulate oxygen-free sub-surface conditions as closely as possible, precautions were taken to preclude exposure of the brine to air during sampling and during the course of the laboratory tests. Although the test method probably did not reproduce conditions precisely as they occur in producing wells, subsequent field trials have shown reasonably good correlation with laboratory results.

Test panels of mild steel, $\frac{1}{2}$ by 4 in., were used in all of the laboratory experiments and were suspended from glass hooks in stoppered liter flasks, filled with the corrosive brine. Before immersion in brine, the test panels were cleaned of mill scale, smoothed with a very fine grade of emery cloth, and weighed. After immersion for seven days at room temperature, the panels were removed from the brine, dipped momentarily into 1 per cent hydrochloric acid, wiped with a soft cloth to remove products of corrosion, washed with distilled water, rinsed in alcohol, dried rapidly and reweighed. The loss in weight was assumed to be due to sulphide corrosion.

It was discovered by the senior author that carbon monoxide, potassium cyanide,* and certain aldehydes* are effective in reducing sulphide corrosion. When a large number of other compounds are compared with the aldehydes they show substantially no inhibiting action for sulphide corrosion when used in quantities up to 500 p.p.m. These compounds, representing a number of classes of materials, included: sodium silicate, potassium ferrocyanide, sodium phosphate, potassium ferricyanide, potassium chromate, sodium nitrite, sodium

hexametaphosphate, pyridine, carbon disulfide, ethyl mercaptan, acetonitrile, isomyl nitrite, dimethylamine, and others. Typical results of the comparative tests with formaldehyde are shown in Table 1.

TABLE 1.—Corrosion Tests with Inhibitors

Inhibitor	Amount, P.P.M.	Corrosion Rate, Lb. per Sq. Ft. per Yr.
None.....	None	0.92
Sodium silicate.....	100	1.00
Ammonium hydroxide.....	500	1.00
Benzaldehyde.....	500	0.70
Pyridine.....	500	0.85
Acetonitrile.....	100	0.95
Sodium hexametaphosphate.....	250	1.00
Potassium cyanide*.....	250	0.108
Formaldehyde.....	125	0.113
Formaldehyde.....	250	0.105

* Brine adjusted to pH 7.5.

The use of carbon monoxide was judged to be impractical for field use because of difficulties involved in obtaining and injecting the gas into wells.

Potassium cyanide was found to be an effective inhibitor when used in the proportions of 250 p.p.m. in brines of pH 7.5 or higher but was relatively ineffective in brines having pH values under 7.5. The extremely poisonous nature of cyanides and their failure to inhibit corrosion in acidic brines are serious obstacles to the use of these compounds for combatting corrosion in oil wells and other field applications.

EXPERIMENTS WITH FORMALDEHYDE AS CORROSION INHIBITOR

Formaldehyde was found effective in inhibiting the corrosion of iron or steel in the test brine. As shown in Table 1, panels of mild steel immersed in untreated North Cowden field brine showed a corrosion loss of 0.92 lb. per sq. ft. per year, whereas when separate portions of the same brine were treated with formaldehyde in the proportions of 125 p.p.m. and 250 p.p.m., the loss of metal by corrosion was reduced to 0.113 and 0.105 lb. per sq. ft. per year, respectively. The panels that had been immersed in brine treated with formaldehyde acquired a bluish gunmetal appear-

* Patents pending.

ance, which was largely retained even after the panel was cleaned with dilute hydrochloric acid.

Insufficient information has been developed to enable a complete and reliable description of the mechanism whereby formaldehyde prevents corrosion. However, as indicated, it appears probable that formaldehyde prevents corrosion by forming a thin but highly protective film of a reaction product on the surface of the steel. The fact that corrosion has been prevented in oil wells by batch injection of formaldehyde as infrequently as once per day tends to confirm the supposition that a formaldehyde reaction product is adsorbed or loosely combined with the ferrous metal. No data are available concerning the possible persistency of the protective action beyond a one-day period.

In the quantity employed as a corrosion inhibitor, formaldehyde reacts with only a small proportion of the hydrogen sulphide normally present in the corrosive sulphide brines. No visible evidence of a chemical reaction is apparent immediately when formaldehyde is added to an acidic sulphide brine. However, within a few hours the clear brine becomes opalescent, a small amount of an insoluble precipitate forms and the brine becomes less acidic.

It seems probable that formaldehyde, in reacting with a small amount of hydrogen sulphide, yields a compound that immediately reacts with the iron surface to form the protective film previously mentioned. Chemical reactions are known in which formaldehyde and hydrogen sulphide react to form mercaptan-like compounds.⁶ However, mercaptans were found ineffective as inhibitors of corrosion caused by sulphide brines. Consequently, it appears that the reaction between formaldehyde and sulphide brines may yield some compound other than mercaptans, possibly in only minor proportions, and that this undetermined compound acts as an effective inhibitor of sulphide corrosion.

FIELD APPLICATIONS OF FORMALDEHYDE

After favorable results had been obtained with formaldehyde in the laboratory experiments, a series of field trials was made in Stanolind Oil and Gas Company's wells in three West Texas areas, to evaluate this compound as an inhibitor of sulphide corrosion.

In these experiments, formaldehyde was introduced into wells by injection into the annulus between casing and tubing. Formaldehyde of U.S.P. grade was used; this product being a 40 per cent aqueous solution of formaldehyde. The treatment was started in the proportion of one quart of the U.S.P. formaldehyde to 25 bbl. of sulphide water produced, the customary treatment being from one to two quarts per day. As the tests progressed, it was found, by inspection of equipment in the treated wells, that in general one quart of formaldehyde per 100 bbl. of water gave adequate protection.

INJECTION METHODS

Various methods were tried for injecting formaldehyde into the annulus and it was found that a lubricator or drip system was the most satisfactory. Chemical injectors of the type commonly used in oil fields to inject emulsion-breaking chemicals into flow lines or tanks generally proved unsatisfactory, mainly because the pumps clogged frequently with paraformaldehyde. Relatively small amounts of this solid form of formaldehyde accumulated as a result of polymerization of some of the gaseous formaldehyde.

Various types of lubricators have been satisfactory. The batch injection of formaldehyde daily does not materially affect the efficiency of the treatment and generally offers advantages over continuous injection as regards cost and maintenance of injection equipment.

A convenient and satisfactory type of chemical feeder or lubricator is shown in Fig. 1. Formaldehyde is stored in a tank

or drum of suitable capacity supported at a sufficient height to permit gravity drainage of the formaldehyde into a small measuring container, usually of 2-quart

measuring and injecting the chemical. In making the treatment, the measuring container is filled with formaldehyde by closing valve A and opening valve B. Then

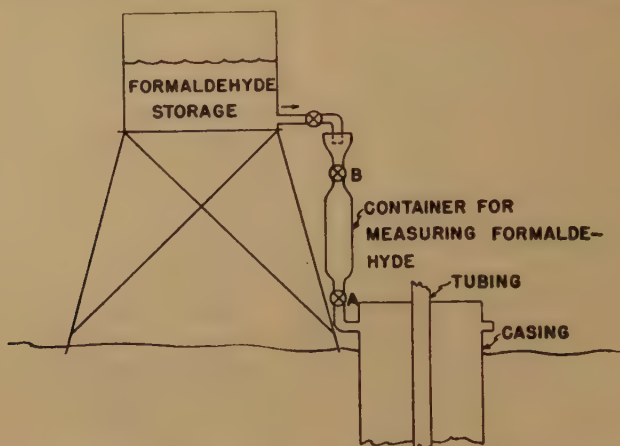


FIG. 1.—DIAGRAMMATIC SKETCH OF FORMALDEHYDE FEEDER AT WELL HEAD.

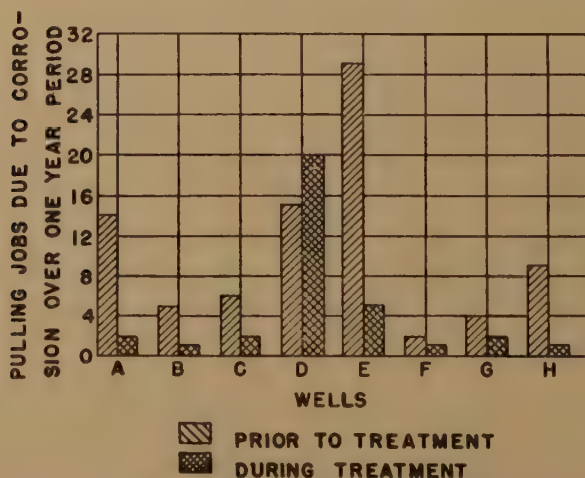


FIG. 2.—REDUCTION IN WELL-PULLING JOBS AS RESULT OF FORMALDEHYDE TREATMENT.

capacity. For wells requiring relatively large amounts of formaldehyde, the 55-gal. formaldehyde container may conveniently serve as the storage container; piping connections being made to the bottom end of the drum. When quite small treatments of formaldehyde are used, it is desirable to dilute the formaldehyde with an equal volume or more of water, to facilitate

valve A is opened and valve B closed, permitting the formaldehyde to drain rapidly into the annulus between tubing and casing.

RESULTS OF FIELD APPLICATION OF FORMALDEHYDE

The field trials of formaldehyde were started in May 1944 and originally were

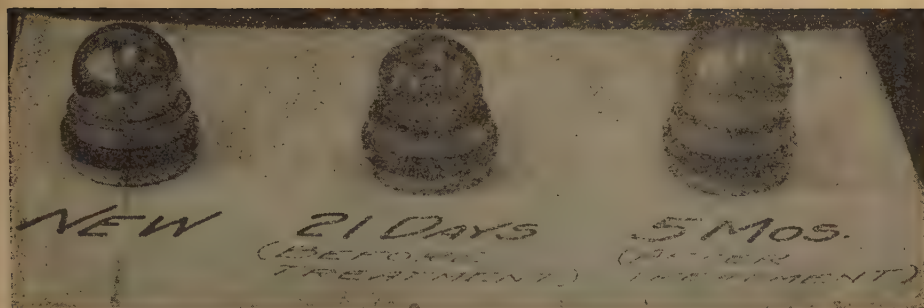


FIG. 3.—COMPARISON OF BALLS AND SEATS TAKEN FROM WELL BEFORE AND DURING FORMALDEHYDE TREATMENT.



FIG. 4.

FIG. 5.

FIG. 4.—PUMP RODS IN WELL A AFTER ONE YEAR OF INHIBITOR TREATMENT.

FIG. 5.—TYPICAL CONDITION OF PUMP RODS AFTER ONE YEAR OF SERVICE IN AN UNTREATED WELL.

set up on six wells. The value of the formaldehyde treatment became apparent so quickly that use of the treatment was soon expanded. In some cases formaldehyde

start of the field trials, a detailed examination was made of the tubing and rods removed from the wells under test. It was found that the formaldehyde treatment

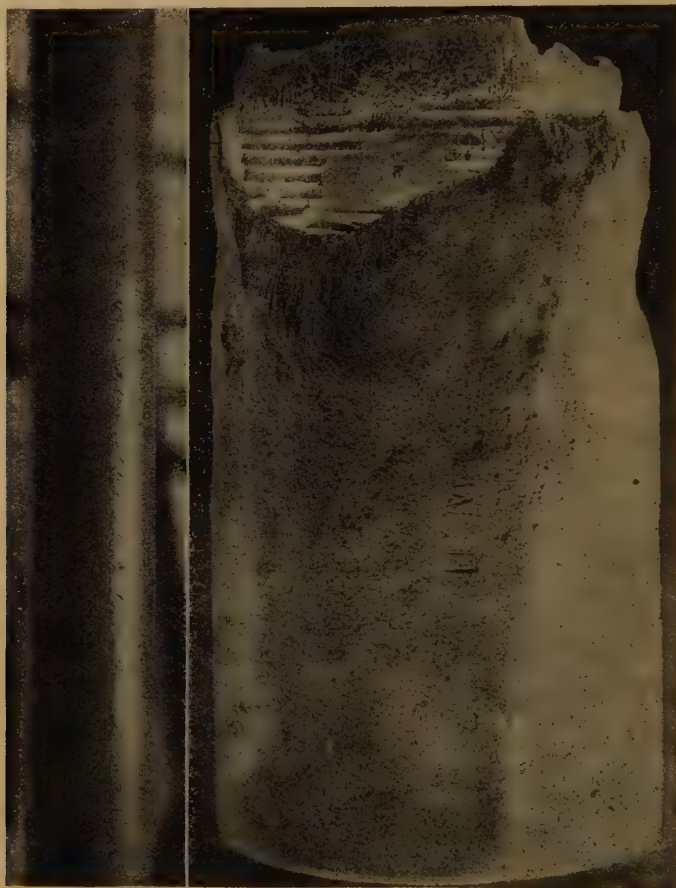


FIG. 6.

FIG. 7.

FIG. 6.—TUBING FROM WELL AFTER ONE YEAR OF INHIBITOR TREATMENT.

FIG. 7.—TUBING FROM WELL NOT TREATED WITH FORMALDEHYDE.

effected a notable reduction of corrosion but did not decrease corrosion as completely as it did on the remaining test wells. The cause was finally traced to electric currents in the flow lines and pull-rod lines of the wells. It was found that installation of an insulating flange in the flow line near the well head virtually eliminated this type of corrosion.

Somewhat more than a year after the

had virtually stopped sulphide corrosion of the subsurface equipment. The laboratory tests had indicated that formaldehyde would reduce the rate of sulphide corrosion about 85 per cent whereas the field trials indicated that the decrease is nearer 100 per cent. This difference possibly is due to the absence of oxygen in the field tests, which could not be excluded from brine used in the laboratory experiments.

The significant decrease in the number of pulling jobs effected on the test wells by the formaldehyde treatment is shown graphically in Fig. 2. This decrease in pulling jobs led to important net savings in pulling expenses and replacement of material for the treated wells. The practical benefit of the formaldehyde treatment is even more significant in view of the fact that the equipment in most of the wells was in poor condition when this treatment was started. Many of the pulling jobs occurring during the period of treatment are believed actually due to failure of equipment, which was badly pitted and corroded prior to treatment with an inhibitor. The failure of well D to show good response to the formaldehyde treatment is attributed to large electric currents entering the well on the flow line, poor condition of the string of rods at the beginning of the test and trouble caused by disintegration of a 50-ft. length of rubber hose suspended in the annulus for injection of formaldehyde. Five pulling jobs were caused by pieces of this hose, clogging perforations in the anchor and between balls and seats.

Some of the more important data pertaining to the trial wells are summarized in Table 2.

TABLE 2.—*Inhibition Results in Eight West Texas Wells*

Well	Pulling Jobs			Average Water Production, Bbl. per Day	Average Treatment Quarts Formaldehyde per Day
	Years Prior to Treatment	Years during Treatment	Reduction, Per Cent		
A ^a	14	2 ^a	.86	225	2
B	5	1	80	10	1½
C	6	2	67	231	2
D ^b	15	20	Inc. 33	50	2
E	29	5	83	55	2
F	2	1	50	30	1
G	4	2	50	30	1
H	9	2 ^a	78	1	1½

^a Test of 6 months duration.

^b Heavy electric current found on the flow line and equipment in poor condition at beginning of test.

Fig. 3 brings out the effectiveness of formaldehyde in reducing corrosion of balls and seats. In this case balls and seats showed severe corrosion in 21 days under usual operating conditions, whereas no discernible corrosion of balls and seats occurred during five months in which formaldehyde was used. In Fig. 4, pump rods appear free of corrosion after one year of service in well A, during which time formaldehyde was used to inhibit corrosion. Fig. 5 illustrates the usual condition of pump rods in an untreated well after a similar period of time. Fig. 6 shows tubing in good condition after one year's service in a well protected by formaldehyde throughout that period. Fig. 7 illustrates severe corrosion of tubing in an untreated well.

CONCLUSIONS

1. Corrosion of subsurface well equipment by hydrogen sulphide can be almost entirely prevented by daily injection of formaldehyde into the annulus of such wells.

2. The inhibitor treatment with formaldehyde effects important net savings in operating costs.

3. The inhibitor treatment does not prevent corrosion caused in some wells by electric currents entering the well through flow lines. Insulating flanges should be used on such wells in addition to chemical treatment.

ACKNOWLEDGMENT

The authors express their appreciation to Stanolind Oil and Gas Co. for permission to prepare and present this paper; to company engineers in the Producing Department of Stanolind Oil and Gas Co., in particular Mr. L. F. Peterson and others in the Stanolind North Texas-New Mexico Division, for their care and efficiency in conducting the special field tests;

and to Mr. J. A. Clay, Jr., for his able report on the field experiments.

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DISCUSSION

(Warren J. Jackson presiding)

PAUL WEAVER.*—Do you think the first step in the reaction of hydrogen sulphide is a change whereby the OH^- group in the formaldehyde is changed to the SH^- group?

P. L. MENAUL (author's reply).—There was very fine scaling in the bottom of the jars. We know formaldehyde does join with the sulphide. It might be that the sulphide, attacking the iron, combines with the formaldehyde and produces another compound.

PAUL WEAVER.—Do you think you have other aldehydes? What is the formaldehyde as you buy it? Do you think it is pure?

P. L. MENAUL.—It is CH_2O dissolved in water (40 per cent). We think it is pure.

PAUL WEAVER.—The replacement of aldehyde by sulphur can be effected more readily in the presence of one of the higher compounds; with the SH^- group higher compounds would start polymerization. Do you agree with that?

P. L. MENAUL.—We found acetaldehyde about 80 per cent as effective as formaldehyde. It is also slightly affected. It is one of the things for the organic chemist to play with, and I want to be at quite a distance from the operation.

E. R. BROWNSCOMBE.*—Was there difficulty in the sour crude wells with hydrogen sulphide? Did formaldehyde do anything to that?

P. L. MENAUL.—The hydrogen sulphide reacts on the steel, the sulphide combines with the iron, freeing the hydrogen. The hydrogen may leave the steel in the form of bubbles, but this reaction is very slow. Atomic hydrogen penetrates into the steel. If we stop or inhibit hydrogen sulphide corrosion we eliminate hydrogen embrittlement. In eight out of 48 of these wells we extended the life of the rods 1000 per cent.

E. R. BROWNSCOMBE.—How about the sour well—would you suggest installing the formaldehyde treater on it?

P. L. MENAUL.—In this well where previously the tubing lasted only one month and sixteen days, the electrolytic current was not the cause of the rapid corrosion. In the well where we had more failures than the year previous, we found a large electric current of $6\frac{8}{100}$ amp. and we did install an insulating flange there.

C. R. HOCOTT.†—Any usual line current attacks the outside of the casing. Does this get around the sucker rods, or what is your explanation?

P. L. MENAUL.—It will attack the casing eventually, but since the tubing and rods are in contact somewhere, current can go to the casing, to the tubing, and then to the rods and then back from the rods to the tubing, and then to the casing. We found some cases in which the pull-rod line from the pumping unit—the current from a transmission line to the unit—would go to the pull rods and from the rods to the well, then to the pump rods and tubing and the casing. Current can go back and forth from the casing to the tubing wherever a joint is screwed up. There may be a high resistance in some joints and the current will flow back to some other string.

E. R. BROWNSCOMBE.—We have had trouble in sour wells where the wire lines bend and get brittle. Should we use formaldehyde in such wells?

* Atlantic Refining Co., Dallas, Texas.

† Humble Oil and Refining Co., Houston, Texas.

* Gulf Oil Corporation, Houston, Texas.

P. L. MENAUL.—In wire lines this might be prevented or lessened by having a line with high nickel content.

E. R. BROWNSCOMBE.—I wanted to know whether we could protect an ordinary steel line.

P. L. MENAUL.—In the penetration of the formaldehyde in the well, if the tubing is full of fluid it will not fall down through the tubing, but if injected through the annular space, it can be used in a pumping well.

L. H. DIAL.*—Does the film deposited on your equipment eliminate other types of corrosion?

P. L. MENAUL.—Yes, for a short time against other types—it is very difficult to stop oxygen corrosion.

LEE FLOOD.†—Is the protection related to the tarnish you talked of?

P. L. MENAUL.—This seems to be a function of it.

LEE FLOOD.—Could you run your wire lines through a field of some kind?

P. L. MENAUL.—The wire line runs against the tubing and any film put on it would be scraped off. That is why a coating on the interior of the tubing is not effective.

LEE FLOOD.—I assume it does not enter into it.

* East Texas Salt Water Disposal Co., Kilgore, Texas.

† Goldsmith Pool Engineering Committee, Midland, Michigan.

W. J. JACKSON.*—In the eight wells you spoke of where does the corrosion mostly take place? In the top of the well?

P. L. MENAUL.—Throughout the tubing. In one treated well we found corrosion below the perforation, in the tail pipe. It corroded in a short time, so the formaldehyde dropped down the annular space and was pumped back up. The tubing itself above the top of the perforations was found in perfect condition.

R. W. TESCH.†—What is the cost of formaldehyde?

P. L. MENAUL.—About 16 or 17 cents a quart. There is quite a supply in South Texas and it may make the cost even cheaper. It is a 40 per cent water solution, and is commercial formaldehyde. We use about one quart to about 50 bbl. of brine. It is possible that more diluted formaldehyde can be used later on.

LEE FLOOD.—What are the conditions in which it gets back to a gas again?

P. L. MENAUL.—It reverts to a gas but it is palmerized into solid form under certain conditions of temperature.

LEE FLOOD.—Could you introduce formaldehyde in a gaseous condition into the tubing to protect the wire-line equipment coming in and out?

P. L. MENAUL.—The tubing might be several thousand feet deep and filled with fluid and formaldehyde would not drop down it fast enough. You would have to put in formaldehyde in the annulus to have the tubing contents treated.

* Lane-Wells Company, Dallas, Texas.

† T. P. Coal and Oil Co., Fort Worth, Texas.

Performance of Distillate Reservoirs in Gas Cycling

BY W. HURST* AND A. F. VAN EVERDINGEN,* MEMBERS A.I.M.E.

(Houston Meeting, October 1945)

ABSTRACT

A distillate-bearing sand complex is often made up of sand stringers of different permeabilities. In order to take into account the influence of the different permeabilities, "parallel flow" is defined, and this concept is used to compute the recovery efficiency of recycling such a sand complex. In the first approximation the position of the wells with respect to one another is not considered.

In order to compute the effect on the recovery efficiency of the position of the wells, the area of a field is considered to be made up of rectangles; each rectangle containing one input well in the center and two producers located symmetrically with respect to the input well. Formulas are given from which to obtain the pressure and streamlines in a steady-state flow. A method is devised to compute rapidly the successive positions of the dry gas front. If the field is irregular in shape, pressure and streamlines can be obtained by a potentiometric electrical model study. By using the concept of "parallel flow" and the results obtained by mathematical analysis or by electrical model study for a homogeneous formation, the effects of different permeabilities and of the location of the wells can be established. From these studies it is apparent that the efficiency of recycling can be profoundly influenced by differences in permeability among the various parallel strata.

INTRODUCTION

With the discovery of an increasing number of gas-distillate fields in the Gulf Coast, engineers have had occasion to give

more thought to the performance of these reservoirs, as evidenced by the literature published in recent years. In the majority of studies published so far the formations are considered to consist of uniform, homogeneous sand. In this paper the authors wish to bring out the effect of variations in the permeability of the formations on the over-all recovery efficiency of wet gas in cycling operations. The importance of the permeability profile is clearly indicated by the fact that in gas cycling, highly permeable stringers in an otherwise tight sand can allow complete displacement of wet by dry gas in these stringers long before the wet gas in the tight portions of the sand is displaced. This by-passing will be reflected by a reduction in the condensate content of the production sooner than can be anticipated from a mathematical analysis or an electrical model study on uniform sands.

Electrical model studies or mathematical analyses cannot take into consideration the manifold variations of permeability within the reservoir. Experimental as well as analytical difficulties make it necessary to consider the prototype for either of these studies as a perfectly uniform sand. Mathematical analyses are applicable only when a reservoir can be divided into units of simple geometrical form, of uniform thickness throughout. Electric model studies are capable of giving information on reservoirs of any shape or thickness, but it is essential that the sand be considered homogeneous, so that three-dimensional flow can take place.

The method of approach in the following

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* Exploitation Engineer, Shell Oil Co., Inc., Houston, Texas.

paragraphs is comparable to one proposed some years ago for gas cycling in three parallel sand zones by W. Hurst,¹ and extended to include all the permeability variations known to exist within the reservoir. This idea has also been expressed in an intercompany report by E. Brunner and G. L. Hassler, of the Shell Development Co., Emeryville, Calif. Each permeable section that can be traced over a structure is considered as a unit in a parallel arrangement of the sand layers. Furthermore, it is assumed that the potential distribution in each parallel section is the same; as the bottom-hole pressure in a well is fixed for

Coast field where the input wells are located along the axis of the field and are offset by two lines of producers, one on each side. In this arrangement an input well can be considered as located in the center of a rectangle and offset by two producers. The series of rectangles laid side by side simulate the development pattern for the field.

The contents of this paper may be divided into two parts:

1. Considering that only "parallel flow" can take place, it is assumed that the gas-injection wells form a line source (one complete side of a rectangle) and the

TABLE 1.—*Linear Flow Computation of Composition of Flow Stream, Omitting Influence of Position of Input and Output Wells*

(1) Depth of Layer, Ft.	(2) <i>H</i> Thickness, Ft.	(3) Percent- age of Total Sand Thickness	(4) <i>K</i> Permea- bility, Md.	(5) <i>HK</i> Product	(6) Percent- age of Sum of All <i>HK</i> Products	(7) Time*	(8) Order of Exhaust- tion	(9) Wet Gas in Flow Stream, ^b Per Cent
9.295-9.315....	1	1.96	200	200	13.30	.147	1	86.70
	2	3.92	150	300	19.95	.196	2	66.75
	3	5.88	100	300	19.95	.295	3	46.80
	5	9.80	50	250	16.62	.590	4	30.18
	9	17.65	30	270	17.95	.983	5	12.23
9.318-9.320....	2	3.92	9.4	18.8	1.25	3.136	9	2.67
9.323-9.325....	2	3.92	10.9	21.8	1.45	2.703	8	3.92
9.325-9.327....	2	3.92	6.9	13.8	.92	4.261	10	1.75
9.327-9.329....	2	3.92	27.0	54.0	3.59	1.092	6	8.64
9.329-9.332....	3	5.88	3.2	9.6	.64	9.188	11	1.11
9.335-9.338....	3	5.88	.5	1.5	.10	58.800	15	0.20
9.338-9.341....	3	5.88	.5	1.5	.10	58.800	15	0.10
9.341-9.345....	4	7.84	1.0	4.0	.27	29.037	14	0.30
9.345-9.348....	3	5.88	1.7	5.1	.34	17.294	12	0.77
9.348-9.350....	2	3.92	1.5	3.0	.20	19.600	13	0.57
9.350-9.352....	2	3.92	24.6	49.2	3.27	1.199	7	5.37
9.352-9.355....	3	5.88	.5	1.5	.10	58.800	15	0
Total.....	51			1,503.8	100.00			

* Time each layer is exhausted = $\frac{\% \text{ of total } H}{\% \text{ of total } HK}$

^b Composition of flow stream after layer is exhausted.

all sections penetrated, so that flow occurs parallel to the bedding planes of the formation, and therefore is referred to as "parallel flow" in the following paragraphs. This arrangement is analogous to the flow of electricity in an electrical circuit consisting of different resistance paths but with the same voltage drop.

The study will be illustrated by computing the distillate recovery for a Gulf

producers a line sink (the entire opposite side of the rectangle). Under this assumption linear flow occurs across each rectangle in each unit. In other words, the position of the two types of wells in each rectangle is not taken into account. The method lends itself readily to an approximate determination of the efficiency of gas cycling early in the development of a pool without requiring detailed mathematical or electrical model data while placing

¹ References are at the end of the paper.

proper emphasis on the permeability profile.

2. Limiting consideration to two-dimensional flow, a gas-input well is taken as a point source and the producer as a point sink, thereby introducing the influence of the position of the wells in the recovery efficiency of the unit. In this manner, the composite effect of the position of the input and output wells as well as the permeability profile is obtained.

LINEAR FLOW

In linear flow, an input well is considered as a line source of length, W , occupying the entire base of one of the rectangles, and the producer as a line sink of the same length along the opposite side of the rectangle. The resultant flow across the rectangle is linear.

The calculations (Table 1) employ only simple arithmetic. The permeability data used in the calculations are also included. The rate of fluid movement through each parallel section is assumed to follow Darcy's law in its simplest form in accordance with the following equations:

$$\begin{aligned} q_1 &= \frac{K_1 H_1 W}{\mu} \frac{\Delta P}{\Delta L} \\ q_2 &= \frac{K_2 H_2 W}{\mu} \frac{\Delta P}{\Delta L} \\ q_n &= \frac{K_n H_n W}{\mu} \frac{\Delta P}{\Delta L} \end{aligned} \quad [1]$$

where q is the rate of flow; K , the permeability; H , the thickness of the section; W , the width of the rectangle; μ , the viscosity, and $\Delta p/\Delta L$ the pressure gradient, which is constant. Eqs. 1 show that the rate is directly proportional to the product of sand thickness and permeability. The total rate of fluid flow, \bar{q} , equal to the sum of these terms, is expressed by

$$\bar{q} = \frac{W \Sigma K H}{\mu} \frac{\Delta P}{\Delta L}$$

The rate of fluid movement through any given section may also be expressed

$$q_n = \frac{K_n H_n}{\Sigma K H} \bar{q} \quad [2]$$

The time for completely flushing a section of sand equals its volume divided by this rate,

$$t_n = \frac{W f_n L \Sigma K H}{K_n \bar{q}} \quad [3]$$

where f is the porosity and L the length of travel common to all sections.

The total fluid displaced from all sections underlying the rectangle at the instant a single member is swept clean can be expressed as a fraction of the total fluid initially in place, and is equal to the sum of the products of the individual rates and the time, divided by the total fluid volume initially in place; namely,

$$\bar{i}_n = \left(\frac{f_n H_n}{\Sigma f H} \right) / \left(\frac{K_n H_n}{\Sigma K H} \right) \quad [4]$$

In Table 1 the porosity is taken constant so that Eq. 4 simplifies to

$$\bar{i}_n = \left(\frac{H_n}{\Sigma H} \right) / \left(\frac{K_n H_n}{\Sigma K H} \right)$$

which will be unity if the section under consideration is of weighted average permeability.

Under the simplifications used here, the production of each stringer at once changes from 100 per cent wet gas to 100 per cent dry gas; therefore the percentage of wet gas in the flow stream is determined by the order in which the sand sections are exhausted. The percentage of wet gas in the flow stream when one section is swept out can be found by subtracting the value of its HK product, expressed as a percentage of the total HK products, from the composition in the flow stream up to that moment. The cumulative recovery of wet gas is found by integrating the relation between composition of the flow stream and the gas processed. The results are shown plotted in Figs. 8 and 9.

TWO-DIMENSIONAL FLOW

Effect of Location of Input and Output Wells

The simplification used in the preceding section, although affording a rapid means

effect of the location of input and output wells with the influence of the permeability profile in order to complete the analysis of a cycling prospect.

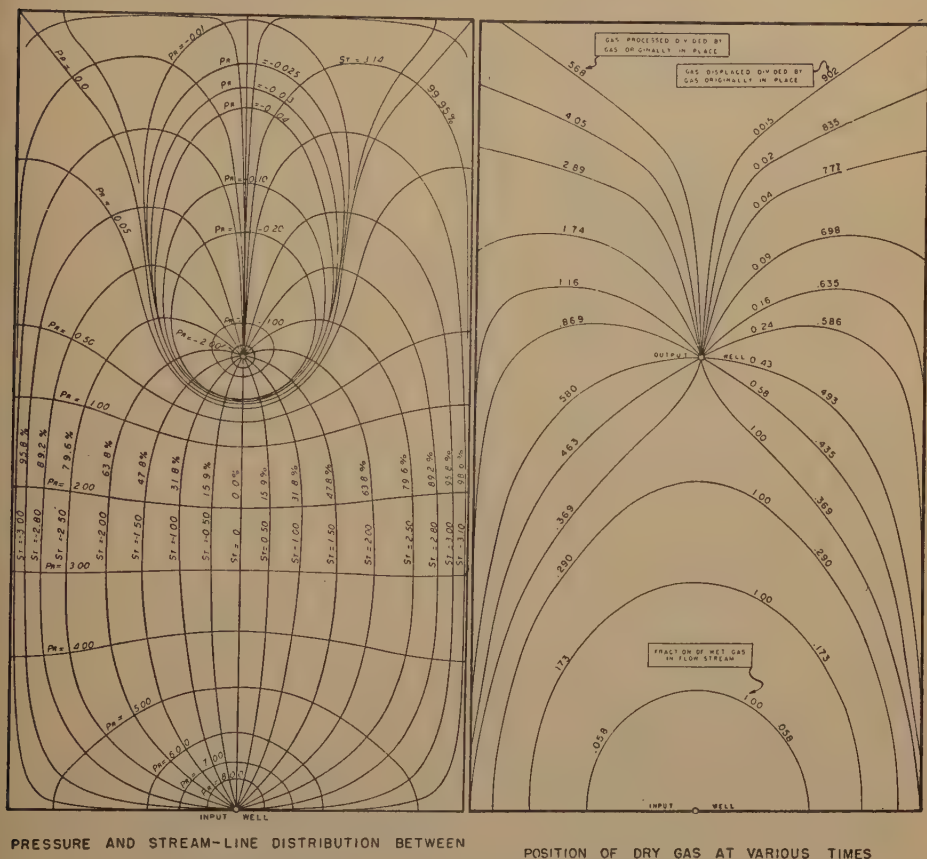


FIG. 1.—CASE A. $L/W = 1.75$; $D/W = 1.00$; L , LENGTH RECTANGULAR AREA; W , WIDTH; D , DISTANCE BETWEEN INPUT AND OUTPUT WELLS.

for evaluating cycling possibilities, cannot serve in the final analysis when it is realized that the location of the wells will also control the efficiency of recovery. It is evident that in practice the wet gas will not be displaced 100 per cent in any individual sand member. There will be areas where the contents will be relatively immobile, areas that will not be swept out within the economic period of a project. Therefore, it is essential to combine the

To undertake this phase of the problem, it is necessary to obtain the influence of the well location on the recovery efficiency either by an electrical model study or a mathematical treatment. Because of the simple geometrical pattern for the field considered here, this problem has been solved by mathematical analysis.

From a consideration of the arrangement of input and output wells for the field, the width W of the rectangle is taken

as 4000 ft., representing the distance between input wells measured along the axis of the structure. The length L of the rectangle, 7000 ft., approximates the

last case shows the producer on the edge of the structure.

Standard texts by Bassett,² Lamb,³ Jeans,⁴ Muskat,⁵ and others show that

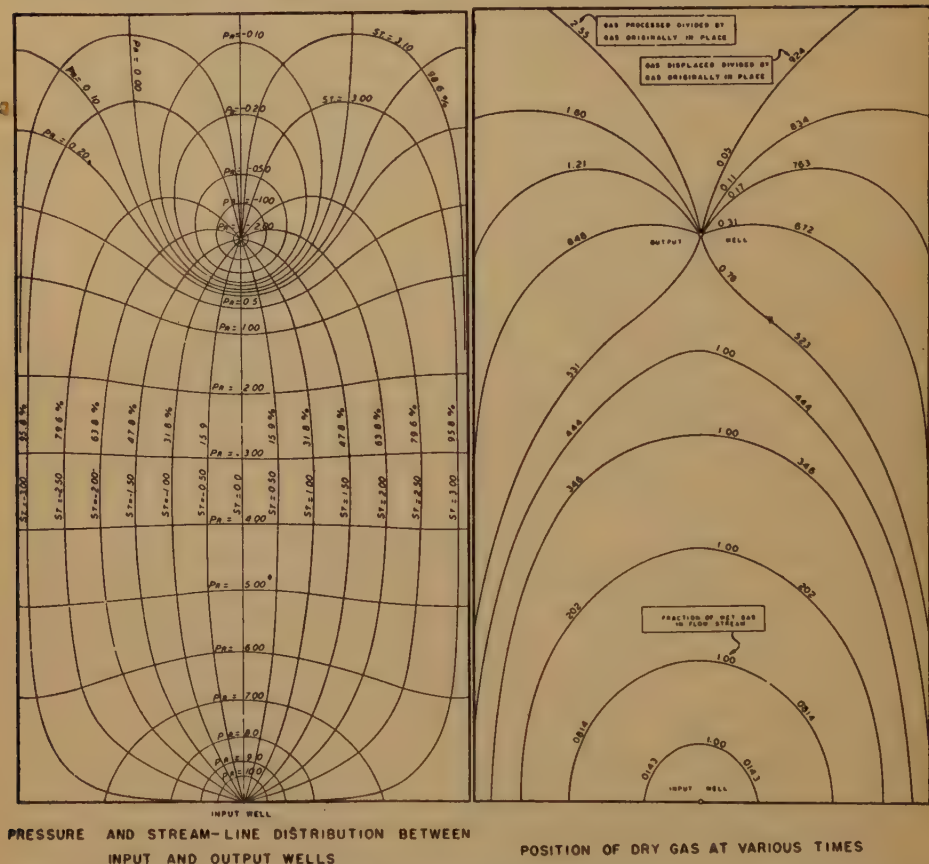


FIG. 2.—CASE B. $L/W = 1.75$; $D/W = 1.25$; L , LENGTH RECTANGULAR AREA; W , WIDTH; D , DISTANCE BETWEEN INPUT AND OUTPUT WELLS.

distance from the axis to the edge of the structure. The input well is taken as the origin of the system, with the x -axis measured along a line through the input coinciding with the base of the rectangle and the y -axis perpendicular to it. Four separate distances D are measured along the y -axis and taken for the location of the output well—namely 4000, 5000, 6000 and 7000 ft.—and are referred to as cases A, B, C, and D, respectively. The

the literature contains numerous examples of point sources and sinks to simulate boundary conditions in a plane for the fluid movement between input and output wells. This method likewise has been employed here, but it is felt that to present the derivation for the solution of the pressure and streamline distribution would distract from the main purpose of this paper—namely, to indicate the importance of the permeability profile of the sand formation

in the cycling operation—therefore only the essential equations are reported.

The equations for the pressure and streamlines can be derived from the Laplace equation,⁶ which for gas is expressed as follows:

$$\frac{\partial^2 P^2}{\partial x^2} + \frac{\partial^2 P^2}{\partial y^2} = 0 \quad [5]$$

and

$$\frac{\partial^2 ST}{\partial x^2} + \frac{\partial^2 ST}{\partial y^2} = 0 \quad [6]$$

where the dependent variables, such as the absolute pressure squared, and streamline values, are expressed explicitly as functions of x and y .

Replacing P^2 by PR , the solution of Eq. 5 for the boundary conditions of the problem is given by the equation at the bottom of this page.

The over-all pressure drop between input and output well expressed by this equation is given by

$$\begin{aligned} P_{\text{input}}^2 - P_{\text{output}}^2 &= \frac{q\mu}{\pi KH} \{PR(o, r_w) - PR(o, D - r_w)\} \\ &= \frac{q\mu\Delta PR}{\pi KH} \quad [8] \end{aligned}$$

where r_w is the well radius q , the production rate of gas, measured at one atmosphere and reservoir temperature, with the other symbols the same as defined in the earlier part.

Further, by expressing the relation

$$\begin{aligned} P_{\text{input}}^2 - P_{\text{output}}^2 &= \frac{2(P_{\text{input}} - P_{\text{output}})(P_{\text{input}} + P_{\text{output}})}{2} \end{aligned}$$

and taking $(P_{\text{input}} + P_{\text{output}})/2$ as the average reservoir pressure Pr , Eq. 8 becomes

$$P_{\text{input}} - P_{\text{output}} = \frac{q\mu\Delta PR}{2\pi PrKH} \quad [9]$$

so that the pressure difference between input and output wells is proportional to the rate of production measured at reservoir conditions; namely q/Pr . The generalized form implied by Eq. 9 has been employed for the calculation of the wave fronts swept out by dry gas.

The equation for the streamline ST is given by the equation at the bottom of page 7, where ST is expressed in radians.

Figs. 1, 2, 3, and 4 give the pressures and streamlines distribution using these formulas. It was found that sufficient accuracy was obtained by only taking one set of terms, $n = 1$, under the summation sign. The plots are comparable to those obtained by potentiometric electrical models.⁶ The values along the streamline, 2.00, 3.00, etc., when divided by π give the fraction of the total gas cycled that flows between a streamline and its image relative to the y -axis. These values are also shown on the streamlines. Thus for the streamline, $ST = 3.00$, 95.8 per cent of the total gas

$$\begin{aligned} 2PR(x, y) = \ln & \left\{ \frac{\left[\cosh \frac{2\pi}{W} (y - D) - \cos \frac{2\pi x}{W} \right] \left[\cosh \frac{2\pi}{W} (y + D) - \cos \frac{2\pi x}{W} \right]}{\left[\cosh \frac{2\pi}{W} y - \cos \frac{2\pi x}{W} \right]^2} \right\} \\ & + \sum_{n=1}^{\infty} \ln \left\{ \frac{\left[\cosh \frac{2\pi}{W} (y - 2nL + D) - \cos \frac{2\pi x}{W} \right] \left[\cosh \frac{2\pi}{W} (y + 2nL - D) - \cos \frac{2\pi x}{W} \right]}{\left[\cosh \frac{2\pi}{W} (y - 2nL) - \cos \frac{2\pi x}{W} \right]^2} \right\} \\ & + \sum_{n=1}^{\infty} \ln \left\{ \frac{\left[\cosh \frac{2\pi}{W} (y - 2nL - D) - \cos \frac{2\pi x}{W} \right] \left[\cosh \frac{2\pi}{W} (y + 2nL - D) - \cos \frac{2\pi x}{W} \right]}{\left[\cosh \frac{2\pi}{W} (y + 2nL) - \cos \frac{2\pi x}{W} \right]^2} \right\} \quad [7] \end{aligned}$$

flows between this line and its image, and only 4.2 per cent of the gas moves in the area bounded by these streamlines and the rectangle. This last fraction of the gas flows fairly fast midway between the input and output wells, where the distance between the streamline 3.00 and the side of the rectangle is small. The velocity is greatly reduced in the region beyond the output well where the distance between the streamline and boundary of the rectangle is much greater, showing that this is an area of relative immobility in the cycling process. A comparison of Figs. 1 to 4 shows that this situation can be improved by locating the output well nearer to the limit of production of a structure.

Figs 1 to 4 also show the area swept out by the dry gas at different stages of the cycling process. The determination of the successive positions of the dry gas front is essentially the treatment of a trajectory problem, and consists in equating the distance of displacement to the product of velocity and time. It is expressed symbolically as

$$\frac{dS_{ST}}{dt} = \frac{dPR}{dS_{ST}}; t = \int_0^{S_{ST}} \frac{dS_{ST}}{dPR/dS_{ST}} \quad [11]$$

where t is the time, S_{ST} is the distance along a given streamline, and dPR/dS_{ST} the pressure gradient, which by Darcy's law is proportional to the velocity. Thus, by joining all points that correspond to

the same time, the dry gas front and hence the area swept out in that period of cycling operation is obtained.

Calculations of this type proved formidable. A shorter method had to be developed in order to make the work of mapping the dry gas fronts practical: First, the times of travel along the path directly between input and output wells were established by analytical means. Then the distances between successive potentials PR and $PR + \Delta PR$ were measured along the different streamlines. From Eq. 11, it can be observed that the time required for a particle of gas to move along any streamline from potential (PR) to potential ($PR + \Delta PR$) is directly proportional to their distances squared, provided ΔPR is not taken too large. Since the exact time for particles to move along streamlines $ST = 0$ is known, the time required for a particle to move along any streamline can be computed. This method has been checked by more rigorous analytics and has proved entirely satisfactory for engineering calculations.

Three sets of values are read along the dry gas fronts of the four plats:

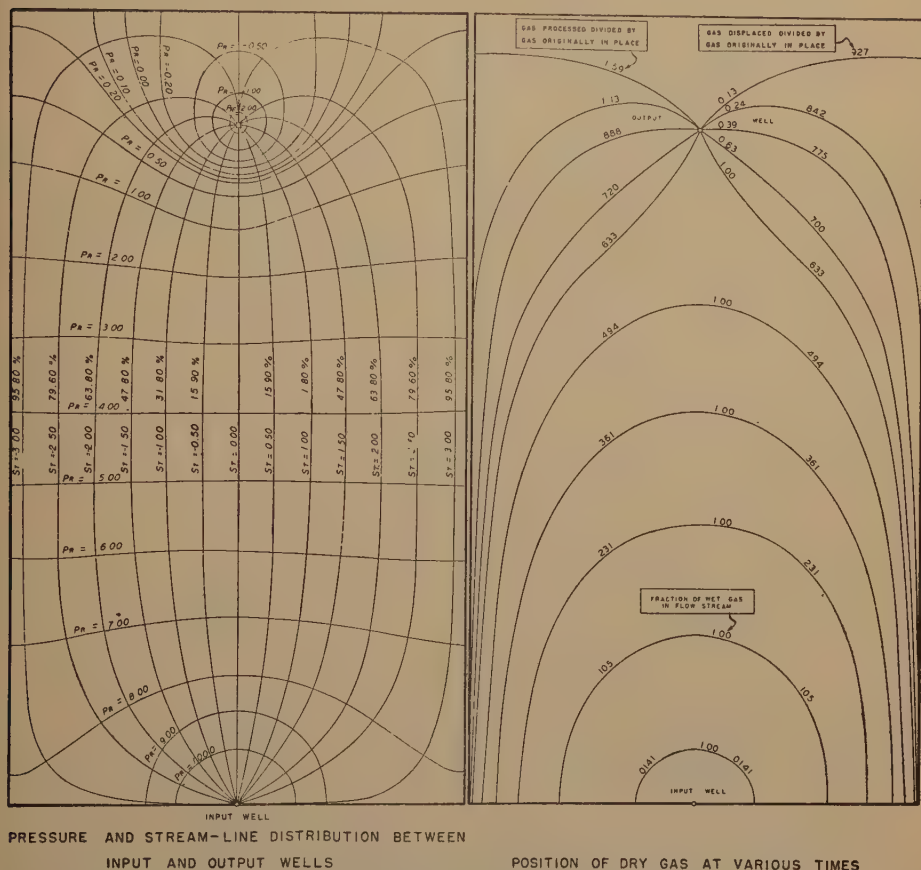
1. The gas processed as a fraction of all gas originally present in the rectangle. This is a time function and can be expressed in days by dividing the gas present in the void space of the rectangle, measured at standard conditions, by one half the rate of gas injected per well per day. The one-half factor is introduced to allow for the sym-

$$\begin{aligned} ST(x,y) = & 2 \tan^{-1} \left(\operatorname{ctnh} \frac{\pi y}{W} \times \tan \frac{\pi x}{W} \right) - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y - D) \times \tan \frac{\pi x}{W} \right) \\ & - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y + D) \times \tan \frac{\pi x}{W} \right) + \sum_{n=1}^{\infty} 2 \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y - 2nL) \times \tan \frac{\pi x}{W} \right) \\ & + 2 \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y + 2nL) \times \tan \frac{\pi x}{W} \right) - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y - 2nL + D) \times \tan \frac{\pi x}{W} \right) \\ & - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y + 2nL - D) \times \tan \frac{\pi x}{W} \right) - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y - 2nL - D) \right. \\ & \quad \left. \times \tan \frac{\pi x}{W} - \tan^{-1} \left(\operatorname{ctnh} \frac{\pi}{W} (y + 2nL + D) \times \tan \frac{\pi x}{W} \right) \quad [10] \end{aligned}$$

metry of the injected well relative to the two producers.

2. The fraction of wet gas in the flow stream at any time.

0.741 of the gas originally in place have been processed, corresponding to cases A, B, C, and D, respectively. Thus by-passing will occur for case D when



recovery of wet gas at the economic limit—64, 78.5, 90, and 96 per cent recovery for cases A, B, C, and D, respectively—shows the effect of spacing. Although case

Permeability Profile

Figs. 5 and 6, whether constructed from data obtained by electrical model study

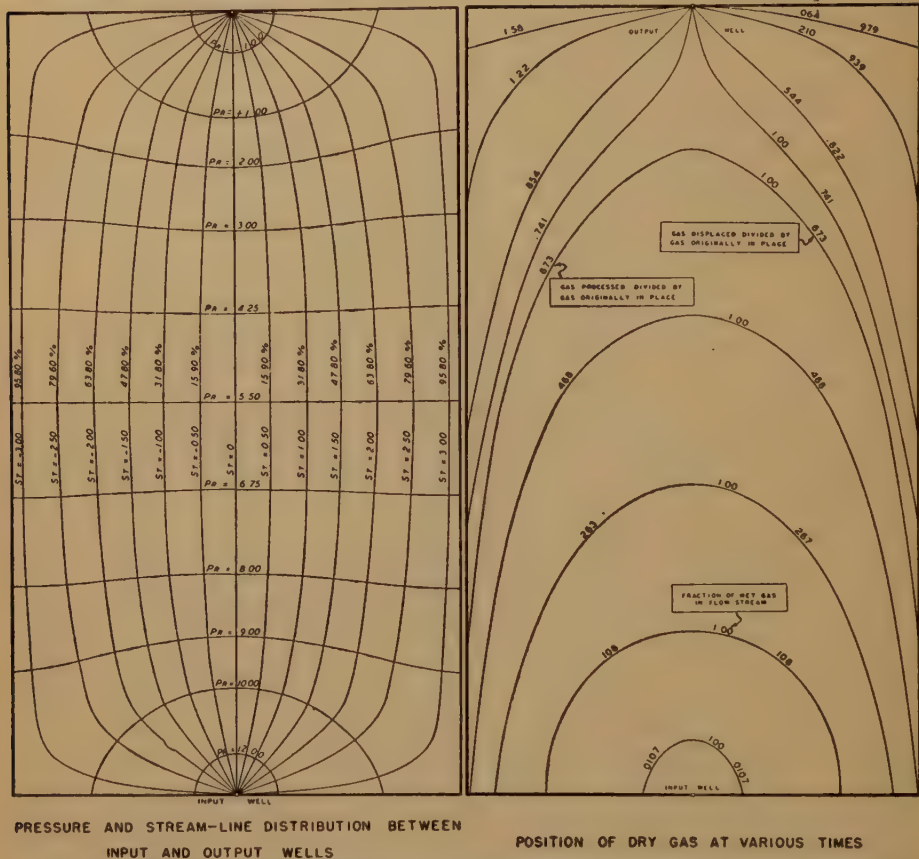


FIG. 4.—CASE D. $L/W = 1.75$; $D/W = 1.75$; L , LENGTH RECTANGULAR AREA; W , WIDTH; D , DISTANCE BETWEEN INPUT AND OUTPUT WELLS.

D shows the greatest recovery for cycling, there are the disadvantages of edge wells that make this arrangement untenable, such as the possibility of drilling dry holes, serious edge-water conditions, and the large pressure drop encountered in cycling, at this position. It should be added that the richer the original gas mixture, the smaller the percentage of wet gas required in the flow stream at the economic limit, thereby permitting a greater over-all recovery efficiency for the operation.

or mathematical deduction, can be applied to determine the effect of cycling any number of sand layers of different permeabilities overlying each other for any shape of field, provided the well arrangement in every rectangle or model is the same.

As in linear flow, the permeability profile is one of the criteria in determining the advance of the dry gas fronts relative to one another, and in establishing the composite recovery of wet gas from the reservoir. Thus the greater the permeability

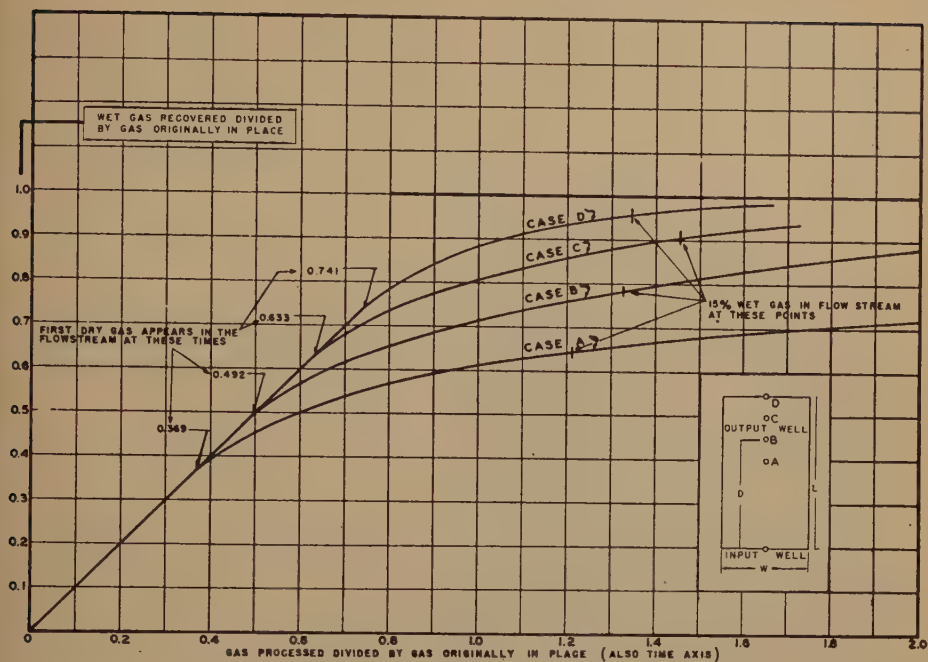


FIG. 5.—WET GAS RECOVERED VS. GAS PROCESSED.

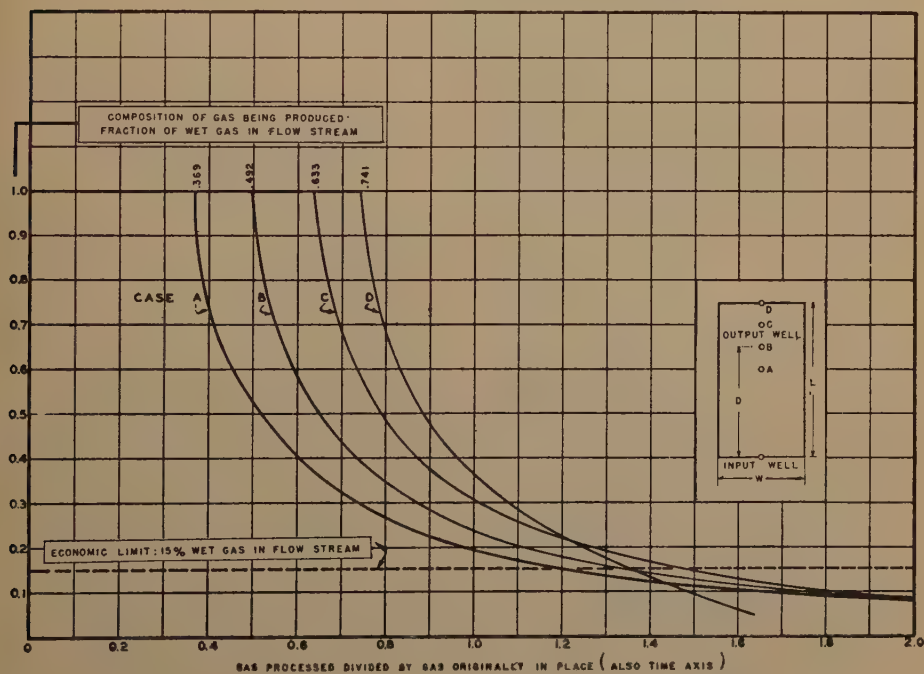


FIG. 6.—COMPOSITION OF GAS PRODUCED VS. GAS PROCESSED.

of a sand member, the further the dry gas front is advanced at a given time compared with another member of lower permeability. Fig. 7 shows the positions of the

rate of movement in a given sand interval is directly proportional to the product of sand thickness and permeability, divided by the sum of the HK products. Further, if

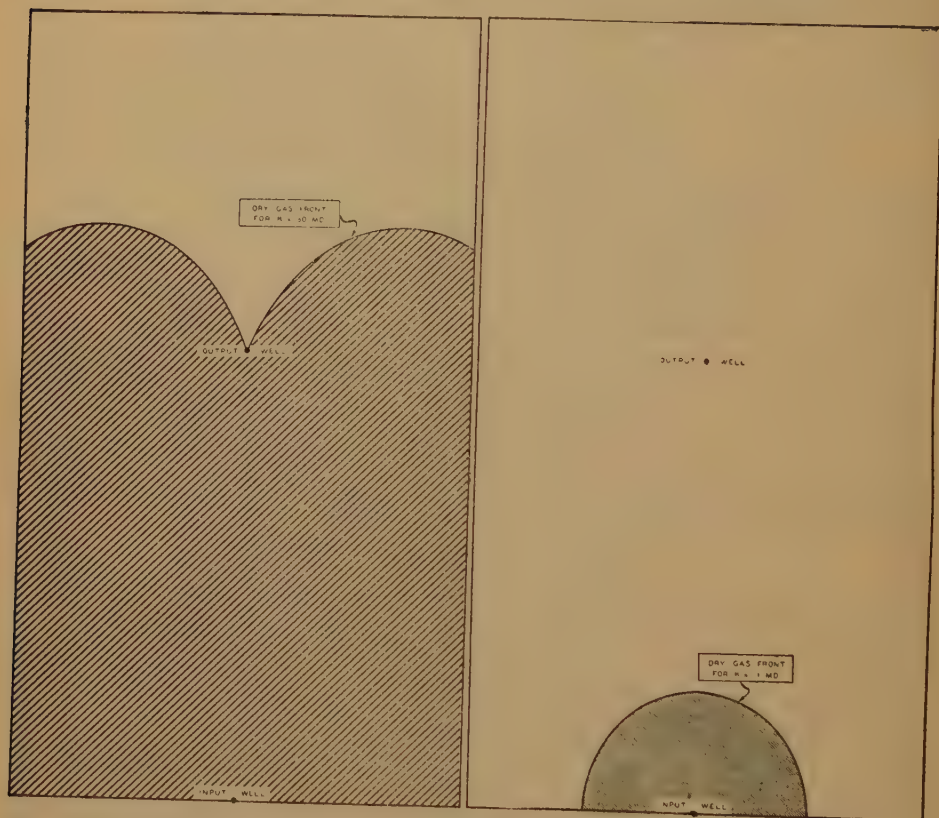


FIG. 7.—POSITION OF DRY GAS FRONT FOR SAME ELAPSED TIME IN TWO PARALLEL SECTIONS OF DIFFERENT PERMEABILITY.
CASE A: $L/W = 1.75$; $D/W = 1$.

dry gas fronts for the same time, corresponding to two different sections, one of 30 md. and the other of 1 md. permeability. In the time the dry gas in the highly permeable sand has swept out most of the area and reached the output well, the dry gas front in the second sand has only advanced a short distance from the input well, so that this tight sand is still producing 100 per cent wet gas.

The computations required are similar to those for "linear flow." As before, the

A denotes the area of the field, X the volume of gas processed, expressed as a fraction of the volume originally present in the section, and t the time, the volume of gas processed from each layer is given by

$$\begin{aligned}
 t \times \frac{K_1 H_1}{\sum K H} \bar{q} &= f_1 X_1 H_1 A \\
 t \times \frac{K_2 H_2}{\sum K H} \bar{q} &= f_2 X_2 H_2 A \\
 t \times \frac{K_n H_n}{\sum K H} \bar{q} &= f_n X_n H_n A
 \end{aligned} \quad [12]$$

which simplifies to the proportionality

$$X_1:X_2:\dots:X_n \\ = K_1/f_1:K_2/f_2:\dots:K_n/f_n \quad [13]$$

and shows, at any time, that the gas

each of these figures by the thickness of the individual sections, column 5; and dividing their sum, 3.7591, by the total sand thickness 51 ft., gives 0.073708 as the gas that has been processed expressed

TABLE 2.—Composition of Flow Stream and Fraction of Wet Gas Recovered, Allowing for Influence of Position of Input and Output Wells

FOR 50 PER CENT PROCESSING OF GAS IN MOST PERMEABLE STRINGER

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Depth, Ft.	H Thickness, Ft.	K Permeability, Md.	Fraction of Gas Processed ^a	(2) × (4)	Fraction Wet Gas Present in Flow Stream of Each Stringer ^b	HK	Fraction Wet Gas × HK	Fraction of Wet Gas Recovered ^c	(2) × (9)
9.295-9.315.....	1	200	0.500	0.50000	0.531	200	106.2	0.454	0.454
	2	150	0.375	0.75000	0.850	300	255	0.375	0.750
	3	100	0.250	0.75000	1.000	300	300	0.250	0.750
	5	50	0.125	0.62500	1.000	250	250	0.125	0.625
	9	30	0.075	0.67500	1.000	270	270	0.075	0.675
9.318-9.320.....	2	9.4	0.0235	0.04700	1.000	18.8	18.8	0.0235	0.047
9.323-9.325.....	2	10.9	0.0270	0.05400	1.000	21.8	21.8	0.0270	0.054
9.325-9.327.....	2	6.9	0.0173	0.03460	1.000	13.8	13.8	0.01725	0.0345
9.327-9.329.....	2	27.0	0.0675	0.13500	1.000	54.0	54.0	0.0675	0.135
9.329-9.332.....	3	3.2	0.0080	0.02400	1.000	9.6	9.6	0.0080	0.0240
9.335-9.338.....	3	0.5	0.00125	0.00375	1.000	1.5	1.5	0.00125	0.00375
9.338-9.341.....	3	0.5	0.00125	0.00375	1.000	1.5	1.5	0.00125	0.00375
9.341-9.345.....	4	1.0	0.0025	0.01000	1.000	4.0	4.0	0.0025	0.01000
9.345-9.348.....	3	1.7	0.00425	0.01275	1.000	5.1	5.1	0.00425	0.01273
9.348-9.350.....	2	1.5	0.00375	0.00750	1.000	3.0	3.0	0.00375	0.00750
9.350-9.352.....	2	24.6	0.0615	0.12300	1.000	49.2	49.2	0.0615	0.1230
9.352-9.355.....	3	0.5	0.00125	0.00375	1.000	1.5	1.5	0.00125	0.00375
Total.....	51			3.75910		1,503.8	1,365.0		3.7040

^a Expressed as a fraction of the volume of gas originally present in each stringer, employing Eq. 13.

^b Obtained from Fig. 6.

^c Obtained from Fig. 5.

Fraction of total gas processed relative to gas originally present in the sands, $3.75910/51 = 0.073708$.

Composite fraction of wet gas in flow stream for the entire formation, $\frac{1.365}{1,503.8} = 0.9077$. Fraction of wet gas recovered, $3.7040/51 = 0.0726$.

processed from any section is directly proportional to its permeability and inversely proportional to the porosity.

Employing again the data for the permeability profile given in Table 1, and using the information for case A given in Figs. 5 and 6, an example has been worked, which is shown in Table 2. As a starting point, it is assumed that 50 per cent of the most permeable section, $K = 200$ md., is processed. Thus by the application of Eq. 13 the fractions of gas processed in each section are found and given by column 4. To determine the fraction of the gas processed for the entire sand thickness, it is necessary to multiply

as a fraction of the total volume originally present in the sands.

The fraction of wet gas in the flow stream for each section is obtained from Fig. 6. Multiplied by the corresponding HK products, the rate of wet gas production for each section is obtained. The fraction of wet gas in the flow stream for the entire formation is the sum of these values, 1365, divided by the rate at which gas is produced from all sections, 1503.8, giving 0.9077.

The fraction of wet gas recovered from each section is obtained from Fig. 5 and shown in column 9. Weighing these figures for the thickness of the corresponding

section, adding 3.7040 (column 10, Table 2) and dividing by the total thickness, 51 ft., yields 0.0726 as the fraction of the wet gas recovered, originally present in the reservoir.

has been processed. The case for linear flow, which has already been discussed, shows a break through of the dry gas when 0.147 of the original gas is processed, if one considers the rectangle of 4000 ft.

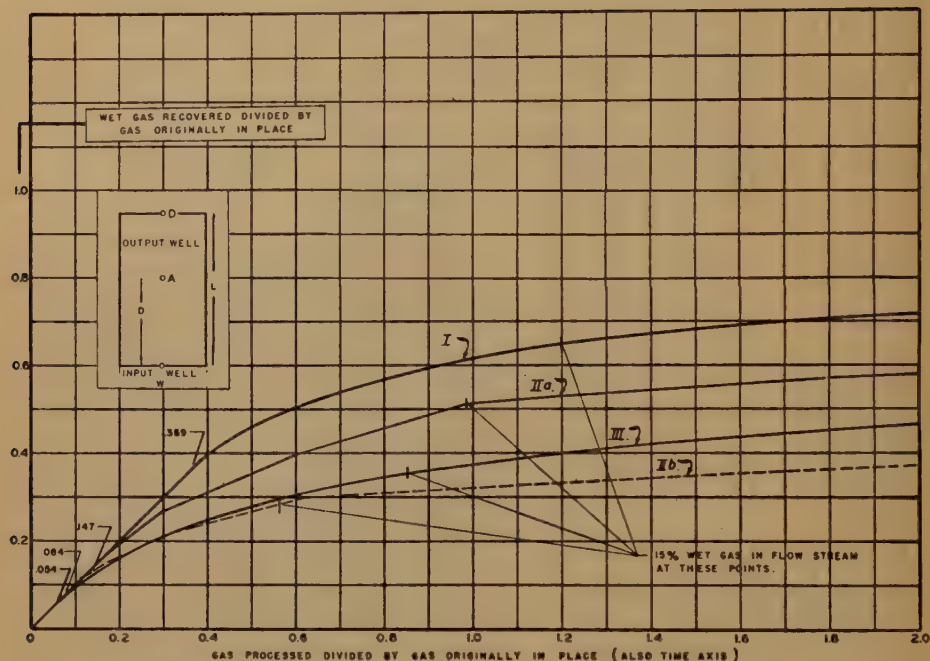


FIG. 8.—WET GAS RECOVERED VS. TOTAL GAS PROCESSED.

- I. Only location of wells taken into account (case A). Sand is considered uniform.
- II. Linear flow, only permeability profile taken into account. Producers located at A.
 - a. Position A considered edge of structure.
 - b. Position A considered as shown in insert.
- III. Parallel-flow location of wells taken into account (case A), employing permeability profile.

The entire procedure is repeated, assuming increasing amounts of gas processed from the most permeable layer, and in this manner the curves of Figs. 8 and 9 are established. As in the linear flow problem, it is assumed that the sand is of uniform porosity throughout. If the porosity is a variable it must be associated with the sand thickness in the calculations for the gas processed and recovered.

Fig. 8 shows that when the entire formation is taken as homogeneous a 100 per cent wet gas is present in the flow stream until 0.369 of the gas originally in the sand

width and 4000 ft. length; that is, neglecting the area beyond well A. If the entire rectangle of 4000 ft. width and 7000 ft. length is considered with the line sink at A, the breakthrough occurs after processing 0.084 of the original sand contents.

These values are reduced to 0.0544 when the combined effects of permeability profile and the well locations of case A are considered.

Relation between Composition of Gas Produced and Total Gas Processed

Fig. 9 shows the relation between the

composition of the gas being produced and the total gas processed, the latter in terms of original gas volume present. Using 15 per cent of wet gas in the flow stream as the economic limit, the plot shows at a

in the formation will be produced eventually, when the reservoir is being depleted. During this depletion period the percentage of wet gas in the flow stream, starting at 15 per cent, will increase continuously and

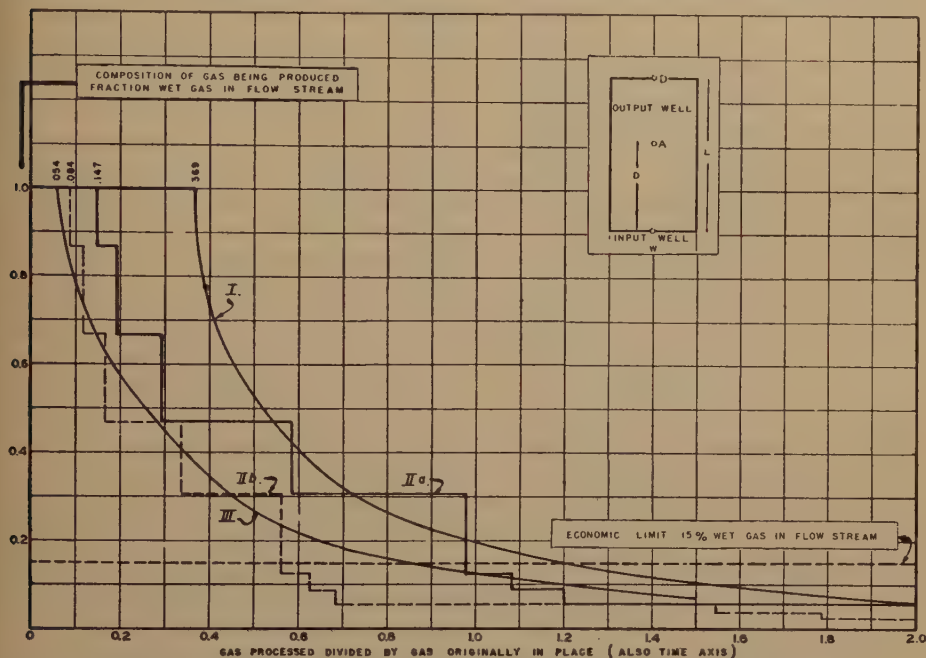


FIG. 9.—COMPOSITION OF GAS BEING PRODUCED VS. TOTAL GAS PROCESSED.

- I. Only location of wells taken into account (case A). Sand is considered uniform.
- II. Linear flow, only permeability profile taken into account. Producers located at A.
 - a. Position A considered edge of structure.
 - b. Position A considered as shown in insert.
- III. Parallel-flow location of wells taken into account (case A), employing permeability profile.

glance the total gas processed up to that point. Fig. 8 gives the wet gas recovered (as a fraction of the gas originally in place) versus the total amount of gas processed. The curves show that for case A, and with the permeability profile employed, only about 35 per cent of the wet gas can be recovered economically. Thereafter the dry gas will dilute the flow stream to such an extent that operations are no longer economical. This low recovery efficiency results from the wide permeability variations in the sand complex and the assumption that only parallel flow can take place. The 65 per cent of wet gas still present

theoretically could approach 100 per cent. This increase in wet gas results from the fact that during depletion the pressure declines faster in the more permeable sands, so that the contribution from these sands to the flow stream decreases faster than the contribution from the less permeable sections. However, during the entire depletion process of the specific reservoir under consideration, retrograde condensation would take place and prevent the distillate content of the wet gas in the flow stream from obtaining its original value. Moreover, during the depletion process the potentials of the wells will

decrease greatly because of the reduction in pressure, the accumulation of condensate around the wells and the fact that a greater portion of the production is obtained from the tight formations.

CONCLUSION

It must be specifically mentioned that the problem treated here is presented only as an illustration of the application of the "parallel flow" for analyzing performance of condensate reservoirs. The low indicated recovery, 35 per cent for the wet gas, demonstrates the profound influence of wide variations in permeability on the efficiency of cycling operations. In this instance the effect may be exaggerated, because only a few permeable stringers occur in an otherwise tight formation.

The contents of this paper have illustrated the application of "parallel-flow" method of analyzing gas cycling. The similarity between the displacement of wet by dry gas in cycling and the displacement of oil by water in secondary recovery, suggests that the "parallel-flow" method of analysis can be used to refine estimates of the over-all recovery efficiency from water-flooding.

ACKNOWLEDGMENT

The authors wish to take this opportunity to express their appreciation to the management of the Shell Oil Company, Inc., for permission to prepare and present this paper for publication.

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DISCUSSION

(R. U. Filling, Jr., presiding)

J. H. GRUY.*—Is it not true that under the parallel flow concept the results are pessimistic, as the high permeability streaks will allow early passage of dry gas, and will the difference in permeability be sufficiently persistent over the entire structure to justify such an assumption?

WILLIAM HURST (author's reply).—Almost any core record on a well will indicate that changes in permeability can be so large that a permeability profile must be considered in the cycling pattern. Whether these permeabilities can be traced from well to well depends on the conditions during deposition of the porous formations. The idealized state of a uniform permeability throughout the field, used so far as a basis in the electrical model studies, generally is not found, and the present concept of parallel flow represents one method of approach that allows a more quantitative analysis of model experiments.

I have tried to imply that, although parallel flow in the true sense may not exist, the method allows for a closer approximation of the results of gas cycling, as it takes into account one more of the factors that influence its efficiency. Depending on the degree of lateral variation in any one streak, the true results may approach either limit, indicated by uniform permeability and parallel flow.

DICK DOBSON.†—Would it not be possible, in view of the rate of intake of the gas, to leave some highly permeable streak blanked off?

WILLIAM HURST.—If such a highly permeable streak occurs in an otherwise far less permeable formation, it may be desirable to blank off such a streak in order to prevent an early breakthrough of dry gas.

L. E. ELKINS.‡—There is one observation I would like to make in support of Mr. Hurst's statements. We have actually completed the recycling of a reservoir in the Gulf Coast and have made a very complete survey of it. The

* Shell Oil Co., Inc., Kilgore, Texas.

† Shell Oil Co., Inc., Kilgore, Texas.

‡ Standard Oil and Gas Co., Tulsa, Oklahoma.

cycling project was an end-to-end sweep and, although the sand is relatively thin, there was no doubt an irregular distribution of permeability, both areally and within the section. Dry gas showed up in the producing wells after 35 to 40 per cent of the gas within the cyclable area had been produced. Our best estimate indicates that after cycling 125 to 150 per cent of

the total gas in place within the cyclable area, we actually had a condensate recovery efficiency of 70 to 85 per cent.

These estimates are bracketed in order to allow for reasonable uncertainty as to the actual total volume of gas within the cyclable area, which we believe can be reasonably estimated within limits of accuracy of 20 per cent.

Some Factors Influencing the Plugging Characteristics of an Oil-well Injection Water

BY WILLIAM F. CERINI,* MEMBER A.I.M.E., WILLIS R. BATTLES,† AND P. H. JONES,†
MEMBER A.I.M.E.

(Los Angeles Meeting, October 1945)

ABSTRACT

A TEST for determining the plugging characteristics of an oil-well injection water has been developed. It consists in measuring changes of the filter rate of a water at constant pressure with cumulative throughput when passing the water through a medium grade sintered glass disk. Application of the test method was made to the water used in the Union Oil Company's experimental water flood of the Chapman zone in the Richfield field, Orange County, California. This water developed increasing plugging tendencies upon aging, even though the finished water from the plant filter exhibited few such characteristics. The plugging material was found to consist of calcium carbonate, ferric hydroxide, and organic substances that were presumed to be bacterial.

Various method of stabilizing this water to prevent the formation of plugging material were attempted. Lowering the pH to approximately 6.4 by injecting carbon dioxide provided a moderately satisfactory means for stabilization but a better method of stabilizing this water was found to be first aging and then filtering.

INTRODUCTION

An experimental water-flood project was started on the Chapman zone of the Richfield field in March 1944 and has been described in a previous paper.¹ It consists of a single injection well drilled between

old producing wells. A water-treating plant using primary alum flocculation, sedimentation and chlorination followed by secondary flocculation, sedimentation and filtration is employed to process the water before injection. In all of the water-treating operations, the system is open to the air, and no attempt is made to prevent the loss of carbon dioxide or absorption of oxygen by the water. The clear water is stored in a covered concrete basin and pumped through a Transite line to the suction of a high-pressure pump at the injection well. The high-pressure tubing in the well to the injection zone is cement lined. The untreated injection water is a mixture produced with the oil from the Chapman and Kraemer zones and is supplied from the disposal system.

Because the injection well was relatively deep (injection zone about 3400 ft.) and would be expensive to replace, it was believed imperative to supply a nonplugging injection water and to develop laboratory procedures for evaluating the treated injection water with respect to its formation plugging properties. This report describes the development and application of the test procedure based on the assumption that the plugging properties could be determined by measuring the progressive decrease in flow rate of the water through a porous medium. If the quality of the injection water was good enough so that the plugging action on the porous medium was of small magnitude, it was reasoned that the tendency to impair flow in the formation would not be serious.

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* Union Oil Company of California, Compton, California.

† Union Oil Company of California, Wilmington, California.

¹ E. C. Babson, J. E. Sherborne and P. H. Jones: Experimental Water-flood in a California Oil Field. *Trans. A.I.M.E.* (1945) **160**, 25.

DEVELOPMENT OF TEST PROCEDURE

Table 1 shows a typical analysis of the water before plant treatment.

TABLE 1.—*Typical Analysis of Untreated Water*

MATERIAL	QUANTITY, PARTS PER MILLION
Sodium (Na by calculation).....	3,963
Calcium (Ca).....	162
Magnesium (Mg).....	46
Sulphate (SO ₄).....	26
Chloride (Cl).....	6,276
Bicarbonate (HCO ₃) (includes any carbonate present).....	409
Iron and aluminum as oxides (R ₂ O ₃).....	3
Total solids (by addition).....	10,885
pH.....	8.1

In addition, the composite sample contained 37 p.p.m. oil, 8 p.p.m. of finely suspended solids, approximately 40 p.p.m. or less of silica, and dissolved organic matter sufficient to impart an oxygen demand of about 40 p.p.m. The experimental water-treating plant did not materially alter the dissolved chemical constituents or oxygen demand of the water, although the pH was reduced to about 7.5. Its major function was to remove the suspended matter from the water. As far as visual observations were concerned, the treated water was crystal clear and exhibited substantially no Tyndall effect.

After numerous experiments in which the water to be tested was passed through a wide variety of filtering materials, including sand-packed columns, Richfield cores, various sandstone specimens and several grades of sintered glass disks, it was concluded that a medium grade sintered glass disk with a permeability of about 300 md. and an area of about 5 sq. cm. was most satisfactory. With this disk, filtered, sterile, distilled water caused substantially no plugging. It was extremely sensitive to the presence of plugging materials in the water under test. With a typical sample of treated water from

the Richfield plant the flow rate was reduced to about one half of the initial rate after a throughput of about 7 bbl. per square foot of disk area.

It was found that the best practical way to keep out extraneous plugging contaminants was to construct the entire system of glass. Therefore, an all-glass system using a medium sintered glass disk with a gravity flow feeder was first employed. This was later modified to a system as shown in Fig. 1. With this system a differential pressure of approximately 5 lb. per sq. in. was imposed across the disk by means of a vacuum on the receiver. The system was manifolded so that a standard solution of distilled water or synthetic brine could be run through the disk; then, after the filter rate had been established, a switch-over could be made to the water under test. This eliminated some of the inconveniences of the former gravity feed system. There was a possibility that air or carbon dioxide escaping from the water at the reduced pressure would cause plugging but check runs made on the same water with the same disk by a gravity system and by a vacuum method did not indicate any difference in the plugging rates, so the vacuum system shown in Fig. 1 was adopted as standard.

While making the tests involved in the development of an apparatus, it was observed that a very thin film of foreign material was deposited from almost all of the waters on the top of the porous medium. From the distilled or synthetic brine waters, this material was green or brown and gelatinous in nature. When examined with a high-powered microscope using polarized light it was dark and had a fibrous appearance similar to that of algae. The material was not soluble in hot hydrochloric acid and turned black when boiled with 18 N sulphuric acid. It was soluble in aqua regia, boiling sodium hydroxide solution and in boiling chromic-sulphuric acid solution. Thus it seems probable that this plugging film was almost entirely organic in nature.

The material deposited by the Richfield water was a fine brown precipitate, which under the microscope appeared to be somewhat gelatinous. Analysis of this material showed it to be about 60 per cent organic matter and 40 per cent inorganic. A micro-analysis of the inorganic portion of a typical sample of the plugging material showed it to consist of approximately 92 per cent calcium carbonate and 8 per cent ferric hydroxide. However, the amount of calcium carbonate obtained in filtering a given quantity of the water increased with the time of aging of the water, while the amount of deposited ferric hydroxide remained constant. The appearance of this calcium carbonate suggested that the water was unstable with respect to the precipitation of this material. Since the value of the Langelier method for predicting whether or not calcium carbonate will be precipitated from a water containing large amounts of dissolved solids is unreliable, actual equilibrium tests were made in which the water was contacted for several days at 150°F. (approximate formation temperature) with powdered calcium carbonate in a closed system that prevented loss of carbon dioxide. There appeared to be a slight loss of dissolved calcium but the amount was within the limits of accuracy of the calcium determination (about 3 p.p.m.). The water also appeared to be substantially stable at about 75°F. (temperature of laboratory tests). A very slight increase in pH, due to a loss in carbon dioxide or small additions of caustic soda, caused the precipitation of calcium carbonate. Although the data were inconclusive, it is possible that slight instability caused precipitation of small amounts of calcium carbonate, which agglomerated organic matter and caused the plugging of test filters.

However, some forms of bacteria in the water undoubtedly were carbon dioxide consumers. Possibly the withdrawal of carbon dioxide from solution caused traces of calcium carbonate to precipitate, which

served as nuclei for the agglomeration of organic matter. In any case, production of a nonplugging water required removal of the traces of precipitated organic matter and calcium carbonate from the water, or a treatment to prevent their appearance.

PREPARATION OF A STANDARD WATER

In order to make quantitative evaluations of various treatments designed to prevent plugging, it was necessary to have a standard reference water which would be nonplugging and could be used as a standard of comparison. Five gallons of distilled water was heavily chlorinated and filtered through a medium grade glass disk into a sterilized bottle. The water was then re-filtered through the disk twice and an effluent was produced that caused no plugging, with a throughput of 12 bbl. per sq. ft. of disk area. The collected sterile water was considered the standard. Contamination was prevented by passing all air that entered the bottle through a solution of potassium permanganate.

TEST PROCEDURE ADOPTED

Using a medium grade sintered glass disk in the vacuum-drive apparatus, the procedure adopted for a water-filtration test was as follows:

1. Referring to Fig. 1, with ball joint *E* open, air pressure was applied at *B* to fill the line from the sample container to *E* with the water to be tested. All other water-carrying lines, including the filter disk compartment, were filled completely with standard water.

2. The vacuum pump was started, reducing the pressure in the receiver until the controlled operating pressure was reached.

3. Stopcock *C* was then opened and flow of standard water was started into the calibrated receiving bottle. After a steady flow rate was established, indicating that the apparatus was functioning properly, a switchover was made to the water to be tested by turning the three-way stopcock

D. Thus, it was unnecessary to disturb the filter disk during the switch-over.

4. Time versus accumulated water-volume readings were made and recorded,

the filter disk would yield a constant rate with the standard water.

It is recognized that varying the test temperature changes the water viscosity

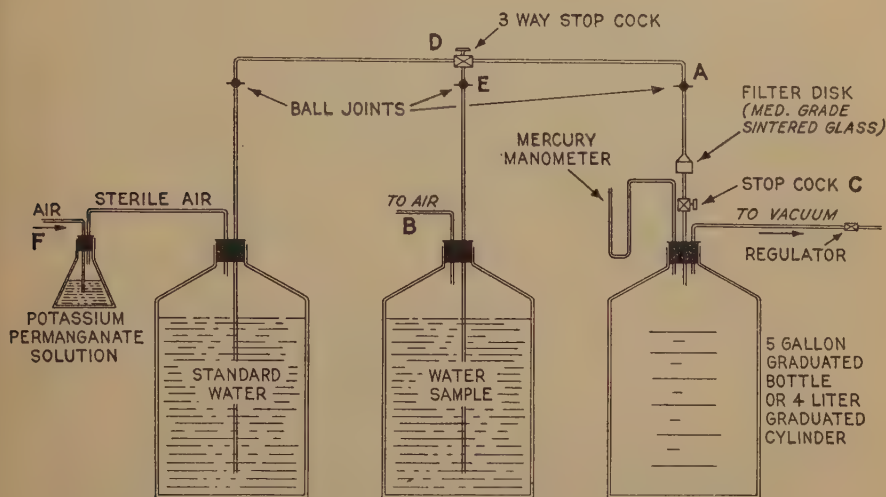


FIG. 1.—APPARATUS FOR LABORATORY FILTRATION TEST OF WATER—VACUUM SYSTEM.

readings being taken at each 40, 100 or 500 ml., depending on the flow rate obtained.

5. The flow was continued until a volume of 4000 ml. of water had passed, or until the time required to pass a 500-ml. portion of water had exceeded 10 min., whichever condition occurred first.

6. The pressure was read and recorded, the vacuum was shut off and the apparatus dismantled, then the temperature of the water in the receiving bottle was read and recorded.

7. After each test the sintered glass disk was cleaned in hot chromic-sulphuric acid solution and rinsed with sterile distilled water. A disk of uniform permeability was not produced by this cleaning technique and the initial flow rate of any test might be higher or lower than that of the preceding test. It was believed that the permeability variations were unimportant, since the variable being studied was the reduction in flow rate after first determining that

and thus affects the throughput rate. The temperature range covered in the tests was small enough to make this viscosity effect negligible when compared with the effect of the plugging action encountered. When the permeability of the porous media was desired, the true viscosity of the water was used.

The results of the tests were plotted on two-cycle semilog graph paper, plotting milliliters per second as the ordinate on the log scale and accumulated milliliters of water as the abscissa on the arithmetic scale. A typical graph is shown in Fig. 2. After the graph had been plotted, the best smooth line was drawn through the points and the increment of the log of the rate, milliliters per second, was divided by the corresponding increment of accumulated throughput to determine a slope for an arbitrary comparative classification of waters. On the basis of experience with the flow of Richfield water through medium

glass sintered disk and cores of approximately 300 md. air permeability, an arbitrary

above, and high standards for water quality may be required.

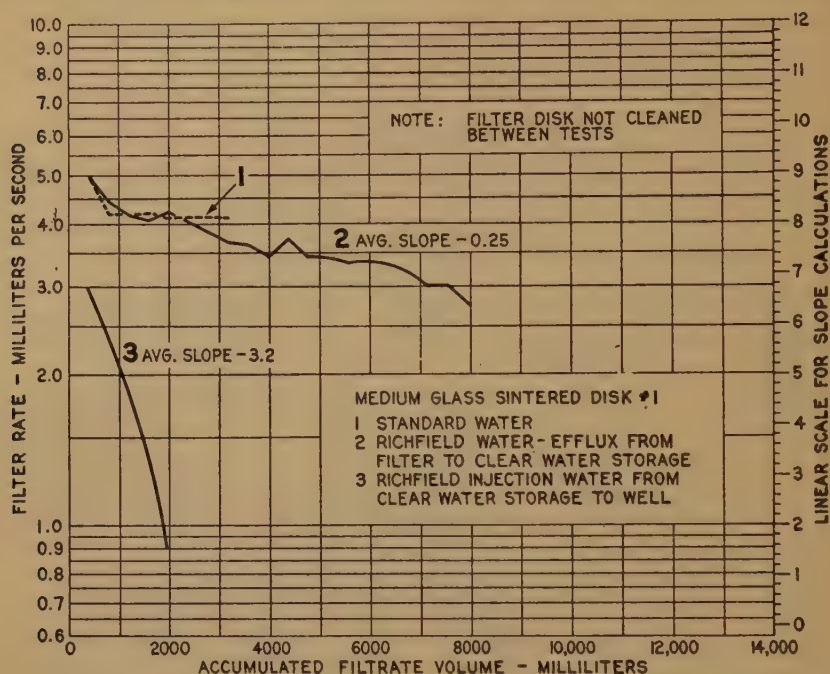


FIG. 2.—RICHFIELD TREATED WATER—LABORATORY FILTRATION TESTS.

trary classification of waters was established as follows:

SLOPE OF GRAPH	ARBITRARY QUALITY CLASSIFICATION
0 to -0.5.....	Good
-0.5 to -1.5.....	Fair
-1.5 to -3.0.....	Poor
Less than -3.0.....	Very poor

This classification may be more exacting than necessary for the Richfield injection project, since the treated water often had pronounced plugging properties, as revealed by the test, but up to the present time available data show little or no decline in water-injection rate for a given input pressure. However, it is possible that selective plugging of low-permeability sands was taking place that could not be detected by the instruments in field use.

With low-permeability sands, a rigorous test procedure, such as that described

SPECIFIC APPLICATION OF TESTING METHODS

Using the method outlined, tests were conducted on treated Richfield water from the plant filter and from the clear-water storage. Fig. 2 illustrates graphically the results of typical tests. The water from the plant filter was usually of better quality than the water from storage. Very rarely the reverse was true; for example, when the filter became dirty and backwashing was required.

In an effort to determine the cause of this deterioration while standing in storage, further tests were conducted in which a water sample from the plant filter was allowed to age. Filter tests were run on this water sample after various periods of aging. The results of the filter tests are shown graphically in Fig. 3, and indicate

that the plugging characteristics of the water increased rapidly with time of aging. Bacteria counts were taken on a sample of the water before each filtration, and on a

time to be insufficient. Accordingly, in all subsequent tests an incubation time of 72 hr. was used before making the counts. This explains the wide discrepancy between

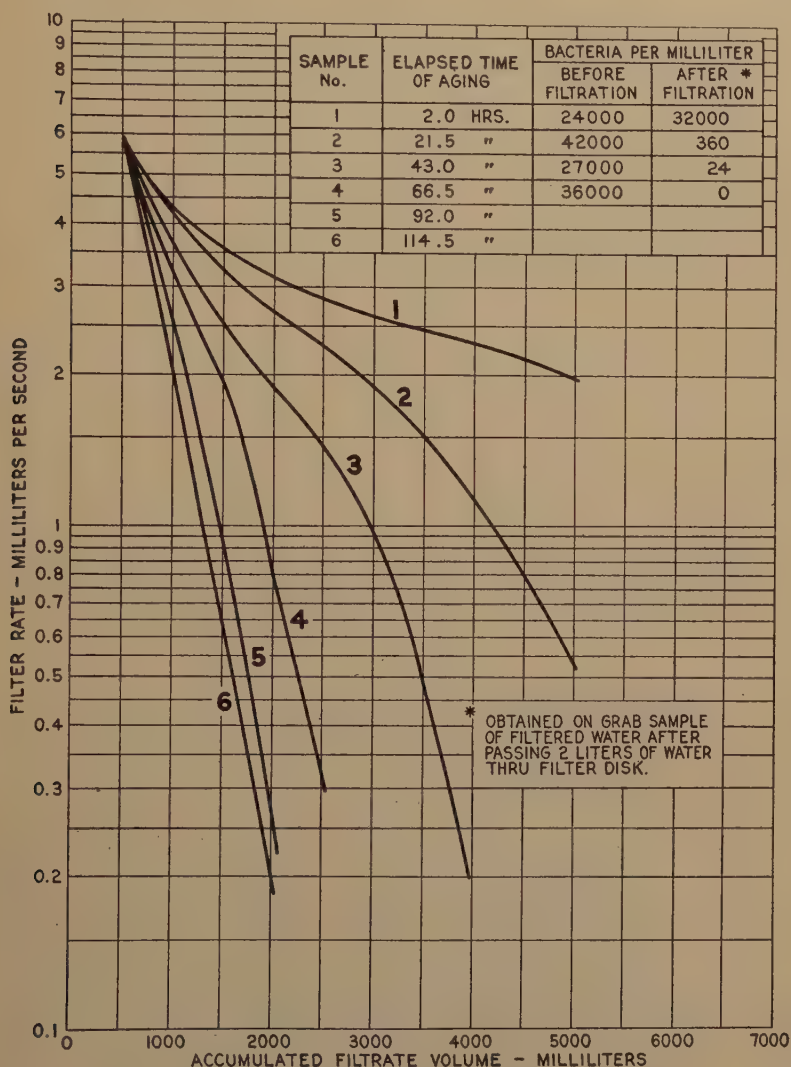


FIG. 3.—RICHFIELD TREATED WATER—DETERIORATION TEST.

grab sample of the filtrate after 2000 ml. of water had been filtered in each test.

For this series of bacteria tests, the cultures were incubated for 48 hr. before counting. Later tests proved this incubation

the bacteria counts shown in Figs. 3 and 4 and those listed in Table 2. The data obtained by the 48-hr. incubation tests are thus of questionable accuracy, and are shown to indicate trends only.

TABLE 2.—Stabilization Tests on Finished Richfield Plant Water

Sample No.	Test Series	Description of Water under Test	pH	Chlorine Content, Parts per Million	Bacteria per Milliliter			Filter Curve Slope	Quality of Water as Determined by Standard Filter Test
					Undiluted Water	Diluted 1 to 1000 with Sterile Distilled Water	Diluted 1 to 1000 with Sterile Richfield Water		
1	A	Sterile standard distilled water.....	—	0	0	0	0	0	Perfect—standard
2	A	Original treated water from filter effluent, Richfield water-treating plant.....	7.5	0	T.N.C. ^a	156,000	164,000	-0.7	Fair
2F	A	Filtrate from standard filter test of sample 2.....	7.8	0	T.N.C.	85,000	93,000	—	—
3	A	Original water (sample 2) after aging for 3 days.....	7.9	0	T.N.C.	850,000	850,000	-2.1	Poor
3F	A	Filtrate from standard filter test of sample 3.....	7.9	0	T.N.C.	360,000	210,000	—	—
3A	A	Sample 3P after aging for 3 days.....	7.9	0	T.N.C.	560,000	650,000	-0.3	Good
3AF	A	Filtrate from standard filter test of sample 3A.....	7.9	0	T.N.C.	710,000	430,000	—	—
3B	A	Sample 3P after aging for 6 days.....	7.9	0	T.N.C.	1,300,000	1,300,000	-0.6	Fair
3BF	A	Filtrate from standard filter test of sample 3B.....	—	0	T.N.C.	840,000	100,000	-0.07	Excellent
3A	A	Sample 3AF after aging for 3 days.....	—	0	T.N.C.	360,000	300,000	—	—
3AAF	A	Filtrate from standard filter test of sample 3B.....	—	0	T.N.C.	340,000	310,000	—	—
4	A	Original sample No. 2 after aging for 6 days.....	—	0	T.N.C.	—	—	-3.4	Very poor
5	B	Original water (same as sample 2) treated with hydrochloric acid to lower pH.....	6.42	0	T.N.C.	40,000	480,000	—	—
6	B	Sample 5 after aging for 3 days.....	6.42	0	T.N.C.	10,000	40,000	-2.9	Poor
6F	B	Filtrate from standard filter test of sample 6.....	—	0	T.N.C.	2,500	5,000	—	—
6A	B	Sample 6F after aging for 3 days.....	7.34	0	T.N.C.	10,000	35,000	-0.6	Fair
6AF	B	Filtrate from standard filter test of sample 6A.....	—	0	T.N.C.	8,000	—	—	—
7	C	Original water (same as sample 2) treated with carbon dioxide to lower pH.....	6.42	0	T.N.C.	41,000	400,000	—	—
8	C	Sample 7 after aging 3 days.....	6.41	0	T.N.C.	9,000	20,000	-0.9	Fair
8F	C	Filtrate from standard filter test of sample 8.....	—	0	T.N.C.	5,000	5,000	—	—
8A	C	Sample 8F after aging for 3 days.....	7.43	0	T.N.C.	2,500	7,000	-0.5	Good
8AF	C	Filtrate from standard filter test of sample 8A.....	—	0	T.N.C.	3,000	12,000	—	—
9	D	Original water (same as sample 2) treated with chlorine to a 10-min. residual of about 4 p.p.m.....	7.48	4.4	—	—	—	—	—
10	D	Sample 9 after aging 3 days.....	7.47	0	0	—	—	-4.6	Very poor
10F	D	Filtrate from standard filter test of sample 10.....	—	0	35	—	—	—	—
10A	D	Sample 10F after aging for 3 days.....	7.93	0	T.N.C.	400,000	310,000	-0.5	Good
10AF	D	Filtrate from standard filter test of sample 10A.....	—	0	T.N.C.	190,000	280,000	—	—
11	E	Original water (same as sample 2) treated with carbon dioxide to lower pH and chlorine to a 10-min. residual of about 4 p.p.m.....	6.31	4.2	—	—	—	—	—
12	E	Sample 11 after aging for 3 days.....	6.30	0	0	—	—	-3.6	Very poor
12F	E	Filtrate from standard filter test of sample 12.....	—	0	580	—	—	—	—
12A	E	Sample 12F after aging for 3 days.....	7.42	0	20	—	—	-0.4	Good
12AF	E	Filtrate from standard filter test of sample 12A.....	—	0	1100	—	—	—	—

^a Too numerous to count.

The inorganic portion of the plugging material obtained from the filter disk in each test was analyzed. All the results of

that some relationship might exist between the calcium precipitation and the bacteria agglomeration. Therefore further tests were

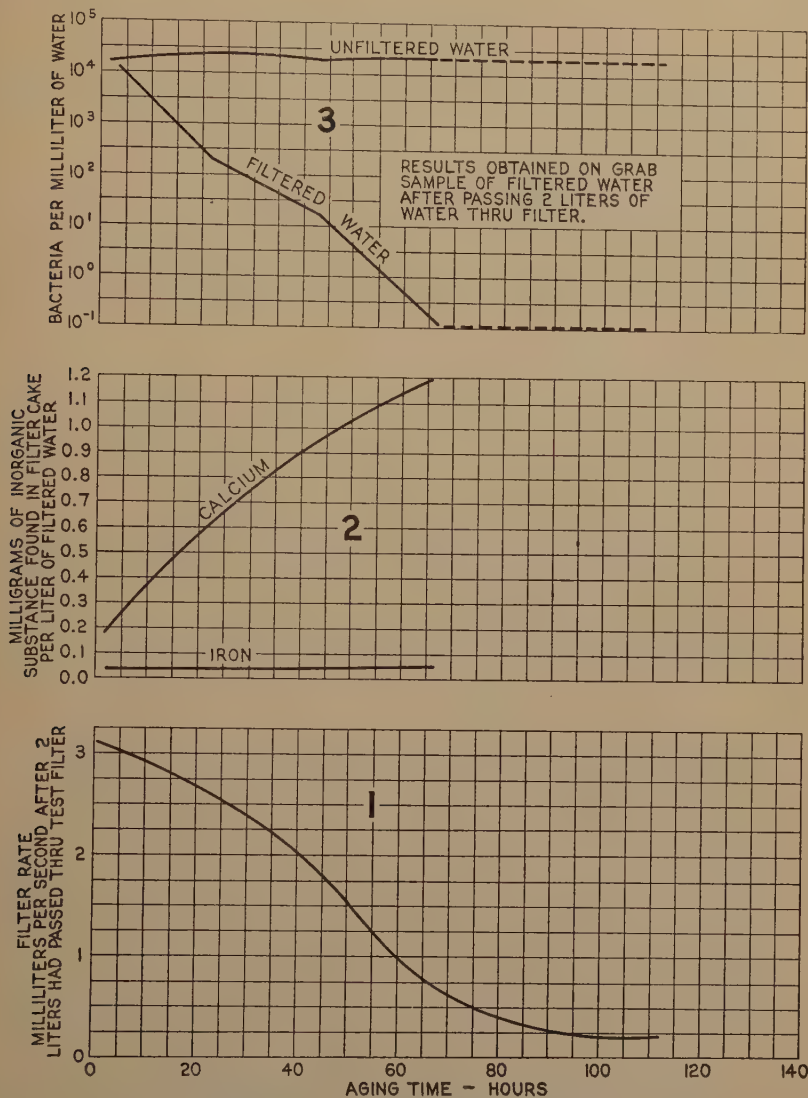


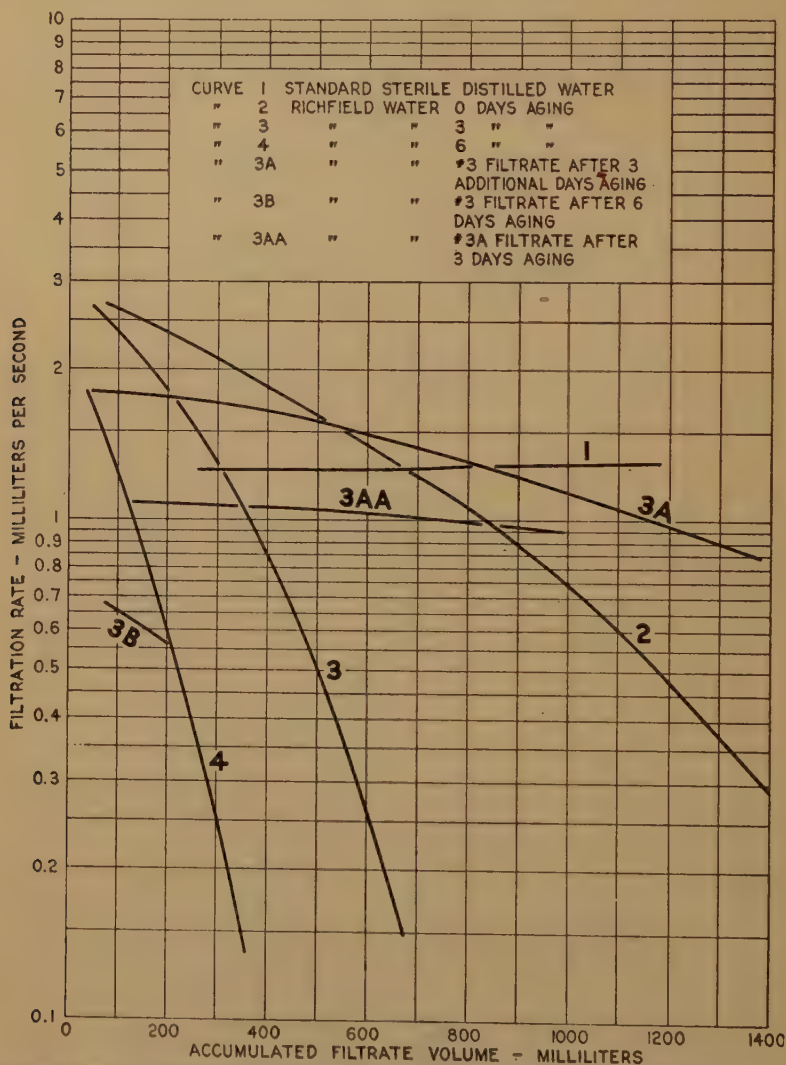
FIG. 4.—RICHFIELD TREATED WATER—DETERIORATION TEST.

Showing effects of time of aging on: (1) plugging properties of the water; (2) the inorganic substances found on the filter cake, and (3) the total and filterable bacteria present in the water.

this series of tests are shown in Fig. 4. Since the filterable bacteria and the calcium content of the precipitate both increased with time of aging of the water, it was thought

conducted in an effort to determine the causes for the growth of plugging materials and to develop a suitable method for preventing their formation.

except for the sample giving curve 4, Fig. 5. Curves 2, 3 and 4 indicate the progressive formation of plugging materials in the unfiltered water as it is aged. This is in



The data covering tests of the filtrates from the aged samples show that a single period of aging and filtration yielded a

relatively stable nonplugging water (see curves 3A and 3B). Furthermore, further aging and filtration of this water produced a product that had practically no plugging characteristics (see curve 3AA).

The next phase of the investigation covered applications of various chemical treatments to the finished water from the Richfield plant. In selecting chemical treatments, consideration was given to the results of earlier laboratory work, which showed that either heavy chlorination of the finished plant water or lowering its pH to approximately 2.0 with hydrochloric or nitric acids caused the formation of a slight milky haze in the water, which, when coagulated, was brown and sticky. The addition of sulphuric acid caused a more pronounced haze. On the other hand, raising the pH above about 8.2 caused some precipitation of calcium carbonate. Such heavy chlorination, or wide pH variation of the water in the plant, was not considered to be economically feasible, and was not investigated further.

In making the tests involving chemical treatments, chemicals were first applied and the samples were allowed to age three days before being subjected to the filter test. In each case, the filtrate was allowed to age three more days and was again tested. The results of the filter tests were plotted on graph paper in the usual manner. A sample for a bacteria count was taken directly following chemical treatment in each test. Similar bacteria count samples were also taken from the water before and after each filter test.

Table 2 briefly summarizes the chemical tests and the results obtained.

Series A tests, which involved no chemical treatments, served as blank determinations for comparison purposes.

Test B series shows the effects on water filtration qualities and bacteria growth of lowering the pH value with hydrochloric acid. Referring to the slope data of the filter curve, the hydrochloric acid treat-

ment gave a water of poorer quality than untreated water. However, this lower pH apparently inhibited growth of bacteria. When the pH again increased after the first filtration, because of the loss of carbon dioxide formed by the reaction of the acid with the bicarbonates present, the bacteria multiplied rapidly.

Carbon dioxide was added to the water in test series C in order to lower the pH value to 6.4, without using a mineral acid or changing the amount of fixed bicarbonate present. The filtration test of the water that had been aged for three days indicates that this carbon dioxide treatment gave a water of better quality than the untreated water. It was also of better quality than any other water obtained by the chemical treatments tried, when the water received no filtration prior to the filtration test for quality.

In test series D, the water was sterilized by chlorine treatment such that the 10-min. residual chlorine content was approximately 4 p.p.m. Although this water showed no bacteria content after three days aging, it had more plugging tendencies than any other water tested. Probably chlorination converted some of the dissolved organic matter, by addition or oxidation, into insoluble compounds that would agglomerate and plug the glass disk. Following filtration and three days additional aging, this water had nearly the same quality as all other waters that received similar aging and filtration treatments. The filtrate from the first filter test apparently became inoculated with bacteria, which, in the absence of chlorine, multiplied rapidly, giving extremely high bacteria counts after three days aging, as shown in Table 2, sample 10A. It is apparent that the total number of live bacteria had little if any effect on the filtration quality of the water, as is also shown in the results for samples 3A, and 3AA.

To observe the effect of carbon dioxide treatment plus chlorine sterilization, the

water sample in test series E was treated with carbon dioxide and chlorine to give a pH value of 6.31 and a 10-min. residual chlorine content of 4 p.p.m. The increase in plugging tendencies that probably was caused by the chlorine treatment is evident. However, the filtrate obtained from this test was of better quality after aging three additional days than waters produced by any other combination chemical and filtration treatment.

None of the chemical treatments described above produced a water that developed no objectionable plugging properties on aging, but in all cases filtration after chemical treatment and aging produced relatively stable nonplugging waters. It should be noted that the untreated water appeared to be of even slightly better quality when subjected to the same aging and filtration treatment.

CONCLUSION

A satisfactory test method for evaluating the plugging characteristics of the treated injection water used in an experimental water-flood in the Richfield district has been developed.

As a result of specific tests performed on this water, some conclusions may be drawn regarding its plugging tendencies.

1. The finished water from the treating plant rapidly developed increasing plugging tendencies upon aging, even though the initial quality of the water from the plant filter as determined from the evaluation test was good.

2. The plugging material formed upon aging of the water was approximately 40 per cent inorganic and 60 per cent organic in nature.

3. The inorganic fraction was approximately 90 per cent calcium carbonate and 10 per cent ferric hydroxide.

4. The presence of live bacteria alone did not appear to cause appreciable plugging.

5. At a pH of 6.4 or lower, the growth

of bacteria in the Richfield water was inhibited.

6. Lowering the pH of the treated plant water from 7.5 to 6.4 by injection of carbon dioxide reduced the formation of plugging material with aging. Treatment with chlorine, hydrochloric acid or a combination of carbon dioxide and chlorine materially increased the formation of plugging materials with aging.

7. Although no entirely satisfactory explanation can be offered to cover the occurrence of the plugging materials and the effects of the various treatments, the data indicate rather conclusively that none of the treatments would in themselves produce a water that would not cause plugging after aging. They also show that a simple filtration after aging would produce a relatively stable nonplugging water of better quality than could be produced by chemical treatment, aging and filtration.

Since storage of treated water with its attendant development of plugging properties is a practical necessity, the installation of a filter in the input-well supply line would appear to be the most practical method for the prevention of plugging of the input well. However, as previously pointed out, the performance of the input well at Richfield has not definitely indicated the necessity for such an installation, and therefore it was decided to defer application of a final filtering stage until well conditions demonstrated its need. With less permeable formations than those being flooded at Richfield, such a filter might be required. Possibly plugging of input wells in Mid-Continent and Eastern secondary recovery projects has been caused by conditions similar to those observed at Richfield, and might be prevented by the installation of final filters for the input water.

It is recognized that the test procedure described herein does not reproduce reservoir conditions accurately, and that in some cases this may be required for a precise evaluation of the quality of injection water.

It is hoped that this report will stimulate further work along these lines and that it may be of some assistance in such investigations.

ACKNOWLEDGMENTS

The authors gratefully acknowledge the many helpful suggestions of Mr. J. E. Sherborne, who assisted in the direction of the work and the preparation of this paper. The collaboration and assistance of Messrs. W. E. Showalter, R. W. Wagoner and R. R. Ormsby in conducting the laboratory work is acknowledged. The authors are grateful to the management of the Union Oil Co. for the permission to publish this paper.

DISCUSSION

C. M. BEESON.*—The experiments described in this paper undoubtedly represent the vanguard of an enormous amount of work to be done in this field. Water injection is spreading to the West Coast, and laboratory

tests to minimize plugging will be of great value; so the authors are to be complimented on an excellent piece of pioneering work.

In the course of the investigation, I wonder if there were obtained any comparisons between the pore channels in oil sands and those in various grades of sintered glass filters.

On a less closely related topic, I would like to ask the authors if they know of any non-oxidizing germicide that might be used successfully in a closed type of water-injection system with bare iron pipes.

W. F. CERINI, W. R. BATTLES, and P. H. JONES (authors' reply).—No comparisons were obtained between the pore channels in oil sands and those in the various grades of sintered glass filters employed. This could be well investigated.

Concerning the application of any nonoxidizing germicide that might be used successfully in a closed type of water-injection system with bare iron pipes, silver has been employed successfully as an electrolyte. The silver is used as the anode and the quantity consumed is minute. Several articles have been published by the American Water Association on this subject. The ultraviolet light could be also used in an open or closed type of system.

* Chemical Engineer, General Petroleum Corporation of California, Los Angeles, California.

Laboratory Investigations of Chemical Changes in East Texas Oil-field Water Affecting its Injection into Subsurface Sands

By F. B. PLUMMER* MEMBER A.I.M.E., AND I. W. WALLING*

(Tulsa Meeting, October 1945; Chicago Meeting, February 1946)

ABSTRACT

BASTIN and others have demonstrated the presence of sulphate-reducing bacteria in oil wells producing salt water. Analyses show that at 125°F. bacteria alone reduce sulphates in East Texas salt water by only 3 per cent in 30 days, forming principally hydrogen sulphide and sodium or calcium hydroxide. The hydrogen sulphide reacts with soluble iron compounds to produce iron sulphide in the absence of oxygen, and ferric hydroxide where oxygen and air are present. Where iron or other metals and iron sulphide are already in the water containing bacteria, 100 per cent reduction of the sulphates is complete in 30 days or less; where magnesium is present, reduction is complete in 15 days. The effects of changes in temperature, of different bactericides, and of concentration of bactericides on sulphate reduction are described in detail and illustrated by tables and curves. The significance of sulphate reduction on corrosive properties of oil-field water is briefly discussed.

CHEMISTRY OF EAST TEXAS OIL-FIELD WATER

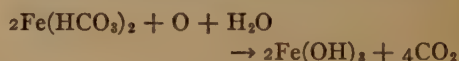
The chemical composition of the water in the East Texas field salt-water disposal pits is shown in Table I.

This salt water corrodes pipes, pumps, and steel tanks excessively, principally because of its content of oxygen, hydrogen, sulphide, and carbonic acid. The carbonates in the water when exposed to air tend to give up carbon dioxide and to precipitate calcium carbonate in large quantities.

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* Bureau of Economic Geology, University of Texas, Austin, Texas.

This forms coatings in tanks, settling pits, and ditches, and soon, unless removed by acid treatment, will effectively clog an injection well and reduce the flow of water back into the ground. The iron compounds in the water, most of which are dissolved from tanks and pipes, are in the ferrous form, and when exposed to the air are oxidized from soluble ferrous carbonate to insoluble ferric hydroxide, resulting in the precipitation of a gelatinous precipitate that will clog oil-field sands effectively:



The sulphates in strong sulphate-bearing water may be attacked by swarms of sulphate-reducing bacteria and more hydrogen sulphide may be produced. The hydrogen sulphide reacts with soluble minerals in the water to form black sludges. A knowledge of the chemistry of each reaction in oil-field water is important to the oil-field engineer, since means must be devised to prevent the formation of harmful precipitates that clog injection wells and to prevent corrosion of tanks by harmful products of biochemical processes.

METHODS OF TREATING WATER BEFORE INJECTION INTO GROUND*

The open system of handling the waste salt water in the East Texas field consists of aerating and chemically treating the water to precipitate the unstable iron,

* For a detailed description of the method of handling the water, see papers by Morris and Dial¹⁻⁵ (references are at end of paper).

magnesium, and calcium compounds, allowing the precipitates to settle out in large settling tanks, and filtering the af-

cium compounds, and calcium hydroxide and aluminum sulphate are added to aid in settling out the precipitates in the set-



FIG. 1a.—BLUM SALT-WATER DISPOSAL SYSTEM IN EAST TEXAS OIL FIELD, SHOWING THREE FLOC-SETTLING PITS IN BACKGROUND, FILTER INSTALLATION ON LEFT, AND FILTER WASH-WATER PIT IN FOREGROUND.



FIG. 1b.—SUMAN SALT-WATER DISPOSAL SYSTEM.

- A. Oil-skimming pit.
- B. House of mixing and storing chemicals.
- C. Aeration slab.
- D. Floc-settling pits.
- E. Baffles in separating pits.
- F. Filters.
- G. Pit for filter back wash water.

fluent water through large sand filters so that only clear filtrate reaches the intake wells (Fig. 1). Air and chlorine are added to precipitate iron, magnesium, and cal-

ting tanks. Successful handling of oil-field water for subsurface disposal depends upon correct design of the disposal plant and chemical treatment that will bring down all

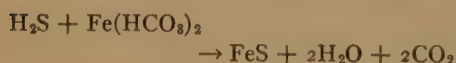
TABLE 1.—Analyses of East Texas Oil-field Salt Water^a

Constituent	Parts per Million	Reaction Value	Percentage Reaction Value
Sodium.....	22,223	966.21	45.55
Calcium.....	1,380	68.86	3.25
Magnesium.....	309	25.40	1.20
Sulphates.....	233	4.85	0.23
Chlorides.....	37,128	1,047.01	49.36
Carbonates.....		0.00	0.00
Bicarbonates.....	525	8.61	0.00
H ₂ S.....	5	pH	7.2

^a Water obtained from end of flow line from gun barrel at point where the water enters the open disposal system.

the insoluble precipitates before filtration, allow as much of the floc as possible to settle, and thoroughly stabilize the water before it passes into the filter. If the water is not properly treated and stabilized, precipitation of insoluble chemicals will continue after the water passes through the filter, and the water sand in the bottom of the intake well will be plugged up rather quickly. Scrapings from the walls of intake wells indicate that in many places the water is not stabilized and that much insoluble matter gets into the intake wells. The insoluble material scraped out of the pipe lines and intake wells consists of black iron sulphide, fine silica silt, and in some places some colloidal silica. In other places the iron sulphide is mixed with insoluble calcium carbonate, which forms a scale on the pipes and oil sand. The chemistry of the calcium carbonate precipitation and methods of its elimination have been discussed,⁶ therefore this discussion will be restricted to iron compounds.

The black iron sulphide originates from the action of hydrogen sulphide upon soluble iron compounds in the water. Thus:



Hydrogen sulphide in East Texas field is derived from the reduction of sulphates by bacteria. Thus:

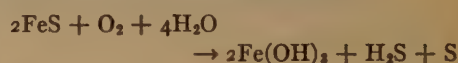


Oxygen is used up by the life processes of anaerobic bacteria and the metallic sulphides react with water to form hydroxide and hydrogen sulphide. Thus:



The hydrogen sulphide then reacts with soluble iron to form insoluble black iron sulphide. The soluble ferrous carbonate in the water comes from the solution of iron in the separators, tanks, filter tanks, filter plates, water pumps, and any unprotected pipe fitting, pipe lines, or tubing through which the water flows after passing the filters.

Furthermore, the black ferrous sulphide is not stable in presence of air-charged or oxygen-bearing water but changes over to iron hydroxide liberating H₂S.



The H₂S may remain in the water, pass through the filter, and precipitate more ferrous sulphide in the intake well. To eliminate this black precipitate and the hydrogen sulphide that produces it, two procedures are necessary:

1. The soluble ferrous bicarbonate may be eliminated by complete oxidation and complete filtration. Sources of iron may be reduced by using wood, plastic, or concrete tanks instead of iron, or lining the iron tanks with rubber or other insoluble protective coatings. All pumps, pipe lines, and fittings need to be coated with or made of nonmetallic material.
2. Bacteria may be eliminated by chemical methods. Since it is expensive, if not impossible, to eliminate all iron from a water-disposal system, it is probably more feasible to eliminate the bacteria.

CHARACTERISTICS OF SULPHATE-REDUCING BACTERIA

The sulphate-reducing bacteria, *Vibrio thermodesulfuricans* (Elon), Fig. 2, that thrive in salt water are strictly anaerobic.

They will not live in air or oxygen, and develop best at comparatively high temperatures, 80° to 140°F.; they reduce sulphates during a 30-day period 98 per

hydrochloric acid and with hydrogen sulphide and organic matter to oxidize these compounds. These reactions use up chlorine and the addition of chlorine results only

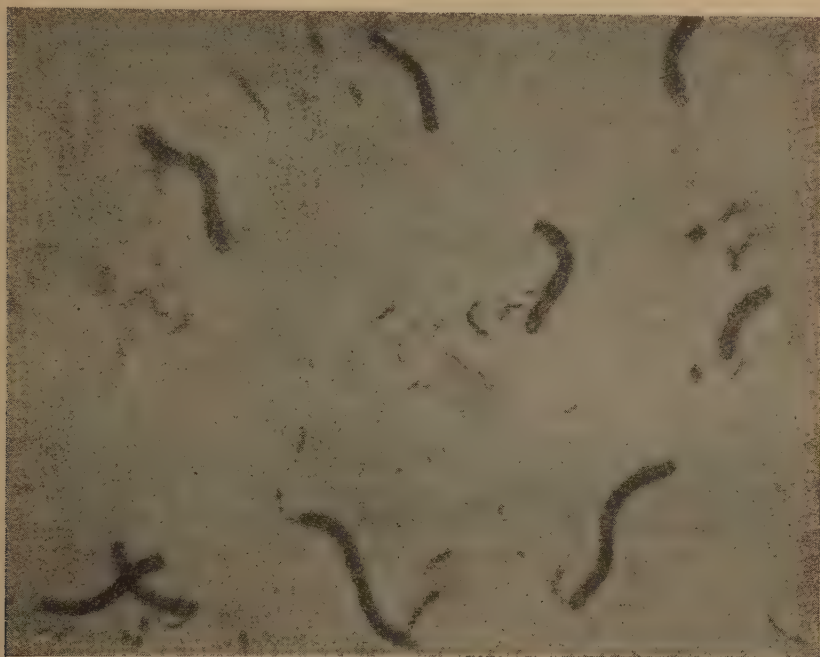


FIG. 2.—*Vibrio thermodesulfuricans* (ELON), SULPHATE-REDUCING BACTERIA THAT OCCUR IN SALT WATER IN THE EAST TEXAS OIL FIELD. (Photograph by H. J. Sawin.)

cent more at 125°F. than at 70°F. At 70°F. no reduction took place during a 20-day period, whereas at 125°F., about 10 per cent reduction takes place during a 10-day period. In East Texas, the common treatment used to attempt to destroy sulphur-reducing bacteria is chlorine, either generated by electrolysis of the salt water or by using liquid chlorine cylinders and defusing the chlorine into the water through porous thimbles. Chlorine treatment is excellent for pathogenic bacteria like *Colon bacillus*, but it is not effective for sulphate-reducing bacteria. Sulphate-reducing bacteria are adapted to strong chloride solutions and small dosages of chlorine in large volumes of water react with water to form hypochlorous and

in increasing the chloride ions and in reducing the pH of the water. Strong dosages of free chlorine will not kill sulphate-reducing bacteria, but the chlorine will oxidize the sulphide so that the iron will be precipitated as hydroxide and not as sulphide. Since some time is required for harmful concentration of hydrogen sulphide to develop, and since salt water passes through the disposal systems and into the injection wells within 24 to 48 hr., one might think the reducing bacteria would not have time to develop harmful amounts of hydrogen sulphide. However, we think the bacteria develop and the sulphate reduction goes on, mostly in partially stagnant places, in the system. Bacteria live in the bottoms of

deep tanks, where circulation is reduced to a minimum, particularly beneath precipitates of iron sulphide in spots wherever a reducing environment prevails and where

filled bottles with the oil-field water through a two-hole stopper (Fig. 3). The bottles were then placed in a constant-temperature incubator (Fig. 3) in the



FIG. 3.—CONSTANT-TEMPERATURE INCUBATOR FOR GROWING BACTERIA IN SALT WATER.

hydrogen sulphide is present and oxygen absent. If a layer of iron sulphide accumulates even on a slab over which water is flowing, the bacteria may live beneath and in the black layer.

LABORATORY INVESTIGATIONS ON SULPHATE REDUCTION BY BACTERIA

A number of experiments were set up in our laboratory to study the reaction of bacteria on East Texas water containing sulphates and the effect of time, temperature, various bactericides, catalytic agents, inhibitors, and other miscellaneous chemicals on the reduction of sulphates brought about by bacteria. These experiments are described, presented graphically, and discussed in the following pages. Water was collected from the wellhead in gallon bottles without allowing the water to come in contact with the air. This was accomplished by first filling the bottles with gas and then displacing the gas out of the gas-

laboratory and allowed to stand at constant predetermined temperatures for 30 days. The concentration of sulphate in the water was carefully determined by standard chemical analytical methods^a at the beginning of the experiment and repeated at the end of each 10-day interval until 30 days had elapsed. At the same time the concentration of hydrogen sulphide produced was calculated. Then the concentration of the sulphates and hydrogen sulphide, in milligrams per liter, were plotted, against time in days, on cross-section paper in order to show the results graphically and enable one to compare a series of experiments most effectively.

EFFECT OF TEMPERATURE ON SULPHATE REDUCTION BY BACTERIA

Bottles of water from the East Texas field were incubated for 30 days at temperatures of 60°, 70°, 80°, 90°, 125°, and

150°F.* and the amount of sulphate reduction and hydrogen sulphide concentration determined at 10-day intervals as follows (Fig. 4):

place at 125°F.; no reduction takes place at 150°F. Therefore, temperature is an important factor in the reduction of sulphates by bacteria.

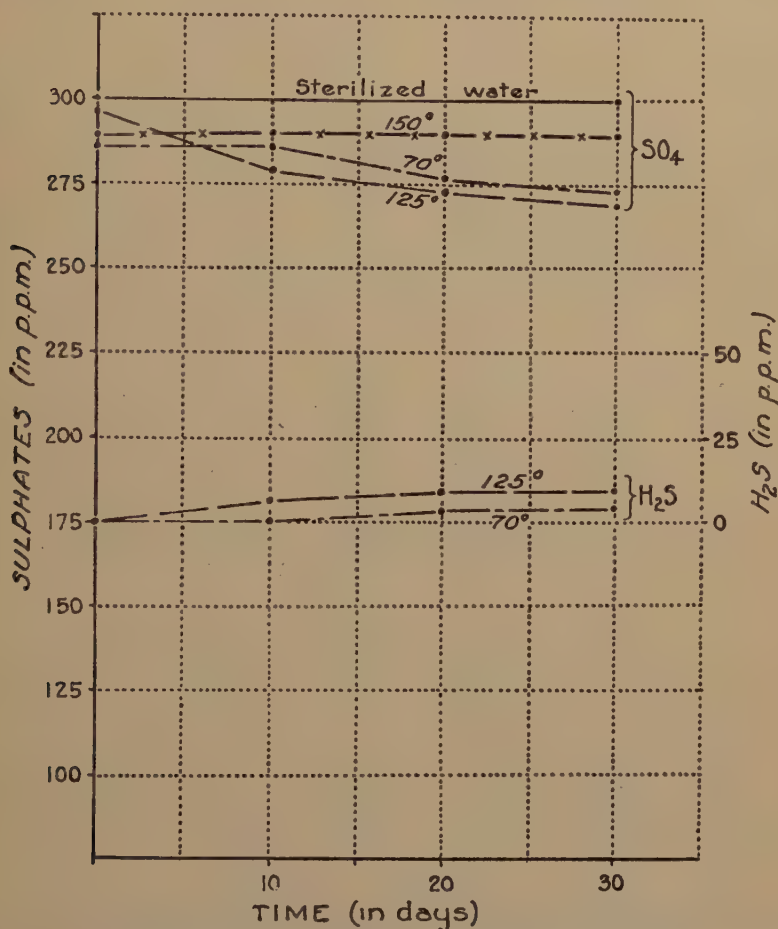


FIG. 4.—EFFECT OF TEMPERATURE ON SULPHATE REDUCTION IN SALT WATER FROM EAST TEXAS OIL FIELD.

It will be noted from these results that if the bacteria are removed by sterilization of the water, no reduction takes place. At 60° and at 70°F. very little reduction is noticed. Largest reduction and most formation of hydrogen sulphide takes

EFFECT OF OIL-FIELD MATERIALS ON SULPHATE REDUCTION BY BACTERIA

The enormous amount of black iron sulphide formed in oil fields and the small amount of sulphate reduction and equivalent hydrogen sulphide formation (less than 15 parts per million), which takes place during 30 days even under optimum conditions in the laboratory, lead one to

* Bacteria probably live up to 180° or 190°F., but are not active above 150°F., and do not cause much reduction of sulphates.

TABLE 2.—*Effect of Temperature on Sulphate Reduction*
MILLIGRAMS PER LITER

Temperature, Deg. F.	Concentration of Sulphate at Beginning	Concentration of Sulphate after			Concentration of H ₂ S after		
		10 Days	20 Days	30 Days	10 Days	20 Days	30 Days
125*	300	300	300	299	0	0	0
60	290	285	291	294	0	0	0
70	286	286	277	274	0	3.0	4.0
80	284	290	280	257	0	1.4	9.5
90	282	279	259	240	1.0	8.1	16.0
125	296	279	273	269	5.6	8.1	9.0
150	289	290	290	290	0	0	0

* Water sterilized in an autoclave at 105°C. for 30 minutes.

believe that some other process than bacteria is responsible for the reduction. In fact, the senior author, during the first period of his work in the East Texas oil field, was willing to eliminate bacteria completely as essential to the process. In order to investigate the effect of other reducing agents, all possible substances with which water in the East Texas field comes in contact, both together and separately, were incubated in the water in 2½-liter bottles for 30-day periods and the amount of sulphate reduction and hydrogen sulphide formation were determined at 10-day intervals. The results are shown in Table 3 and Fig. 5.

These results show that the addition of colloidal iron sulphide sludge increases the amount of reduction of sulphates in water

containing bacteria at the end of 30 days by 60 per cent. Iron rust, metallic iron, and metallic magnesium also accelerate the reaction. On the other hand, the combination of three ingredients—ferrous sulphide, iron rust, and metallic iron—increases the reduction by 90 per cent. Pulverized commercial iron sulphide, on the other hand, increases the reduction only about 10 per cent. If the water is sterilized and the bacteria removed, no reduction takes place. Bacteriologists with whom we have discussed these results inquire whether the increased reduction upon addition of metals and iron sulphide is not due to addition of a large swarm of active, greedy bacteria, which might be mixed with the iron-sulphide sludge. Accordingly, the iron sulphide sludge was sterilized by heating in absence of air in an autoclave at 110°C. for 30 min. and then placed in the salt water to be incubated. The results showed almost as strong a reduction of the sulphate as without sterilization. Therefore, it is concluded, tentatively at least, that the colloidal iron sulphide metal and rust actually accelerate the rate of reduction of the sulphates. The action of the finely divided ferrous sulphide on the sulphates may be a catalytic action, or it may be that ferrous sulphide is a reducing agent removing all oxygen from the water so that anerobic bacteria multiply more rapidly. It may be possible also that an electrolytic action

TABLE 3.—*Effect of Oil-field Materials on Sulphate Reduction by Bacteria at 125°F.*

Material	Concentration of						
	Sulphate at Beginning	Sulphate at 10 Days	H ₂ S after 10 Days	Sulphate after 20 Days	H ₂ S after 20 Days	Sulphate after 30 Days	H ₂ S after 30 Days
Water alone.....	296	279	5.6	273	8.1	260	9.5
Colloidal ferrous sulphide sludge....	292	258	10.0	175	42.5	80	73.0
Iron rust from pipes.....	292	215	2.0	192	35.0	188	37.0
Strip metallic iron from tank.....	292	240	19.3	185	37.5	156	48.0
Combination of the three materials listed above.....	263	216	16.6	33	81.5	0	100.0
Pulverized commercial FeS.....	292	288	1.4	265	10.0	233	20.6
Magnesium + FeS sludge.....	292	111	63.0	0	105.0*		

* Completely reduced in 15½ days.

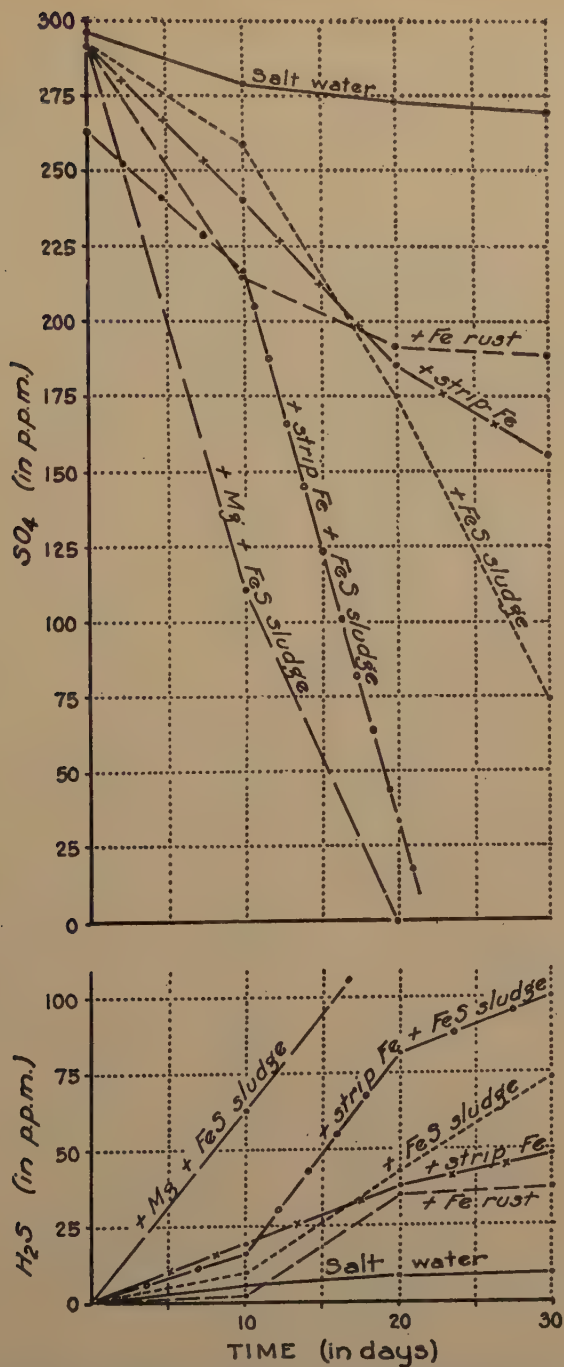


FIG. 5.—EFFECT OF OIL-FIELD MATERIALS ON SULPHATE REDUCTION BY BACTERIA.

TABLE 4.—*Analysis of Black Iron Sulphide Sludge*

Constituent	1 ^a	2 ^b
CaSO ₄	3.30	11.30
CaCO ₃	16.10	8.10
FeS.....	24.30	25.10
Fe ₂ O ₃		
MgCO ₃	0.26	0.21
Al ₂ O ₃	15.30	10.60
SiO ₂	13.30	22.60
Loss on ignition.....		
	72.60 ^c	77.90 ^c

^a Floc from intake pit, Starnes system, Gladewater, Texas. Analyzed by Paul Tapp.

^b Floc from bottom of settling pit No. 3 at suction pipe, Starnes system, Gladewater, Texas. Analyzed by P. A. Witt.

^c The difference between these totals and 100 per cent is represented by organic matter, paraffin, oil, sulphur, and other minor constituents.

is set up in the salt water between the iron sulphide as a cathode and metallic iron as an anode and that this electrolytic action, which is known to bring about solution and corrosion of iron, also aids the growth of bacteria and promotes in some way the reduction of the sulphates. The fact that magnesium aids the reduction of the sulphates more than iron favors the electrolytic theory, since magnesium is higher than iron in the electromotive series. Whatever the cause of the reduction, it is a fact that the presence of iron fragments and ferrous sulphide sludge accelerates the reduction greatly.

Ferrous Sulphide Sludge

Composition.—The ferrous sulphide sludge is not pure colloidal ferrous sulphide,

TABLE 6.—*Effect of Bactericides on Sulphate Reduction by Bacteria*

Amount of Bactericide	Concentration of Sulphate				Conc. of H ₂ S after 30 Days
	At Beginning	After 10 Days	After 20 Days	After 30 Days	
5 grams phenol.....	305	305	305	305	
25 ml. shell D-D (dichlorobutene)...	304	290	298	296	
Chlorine water generated by electrolysis of East Texas salt water.....	202	220	155	66	80
3 ml. of formaldehyde	310	310	310	310	
6 ml. monochlorobutene.....	299	295	292.5	290	
2.5 ml. Lysol.....	275	273	275	277	
1 ml. cresol.....	275	275	275	275	
10 ml. creosote.....	275	271	272	275	
25 ml. absolute methyl alcohol.....	292	190	86	4	102
25 ml. acetone.....	292	220	157	118	62
6 ml. of trichlorobutane.....	292	291	287	287	
25 ml. thiokol.....	275	274	272	269	
25 ml. saturated chlorine water....	304	280	154	35	107

but a mixture of iron sulphide, calcium carbonate, magnesium carbonate, silt, clay particles, and rust particles having approximately the chemical composition shown in Table 4, in which the colloidal ferrous sulphide predominates.

It may be that some of the minor ingredients in the sludge other than iron sulphide are the real catalytic agents, but so far we have not been able to separate out sufficient of the minor constituents other than calcium carbonate, which gave negative results, to be able to check the

TABLE 5.—*Effect of Volume of Colloidal Ferrous Sulphide Sludge on Reduction of Sulphates*

Amount of Ferrous Sludge, Ml.	Concentration of						
	Sulphate at Beginning	Sulphate after 10 Days	H ₂ S after 10 Days	Sulphate after 20 Days	H ₂ S after 20 Days	Sulphate after 30 Days	H ₂ S after 30 Days
Salt water alone.....	296	270	5.6	273	8.1	260	9.5
10.....	292	272.5	5.0	212	25.0	168	45.0
25.....	292	270	7.3	177	40.3	84	73.3
50.....	292	258	10.0	175	42.0	89	72.0
100.....	292	247	20.0	109	70.0	27	94.0
150.....	286	240	16.3	124	57.0	12	97.0

possibility that silts and clays are reducing agents.

Quantity Required for Reduction of Sulphates.—In order to investigate the

incubated in 2½-liter bottles at 125°F. for 30 days with various amounts of ferrous sulphide sludge. The results are shown in Fig. 6 and Table 5.

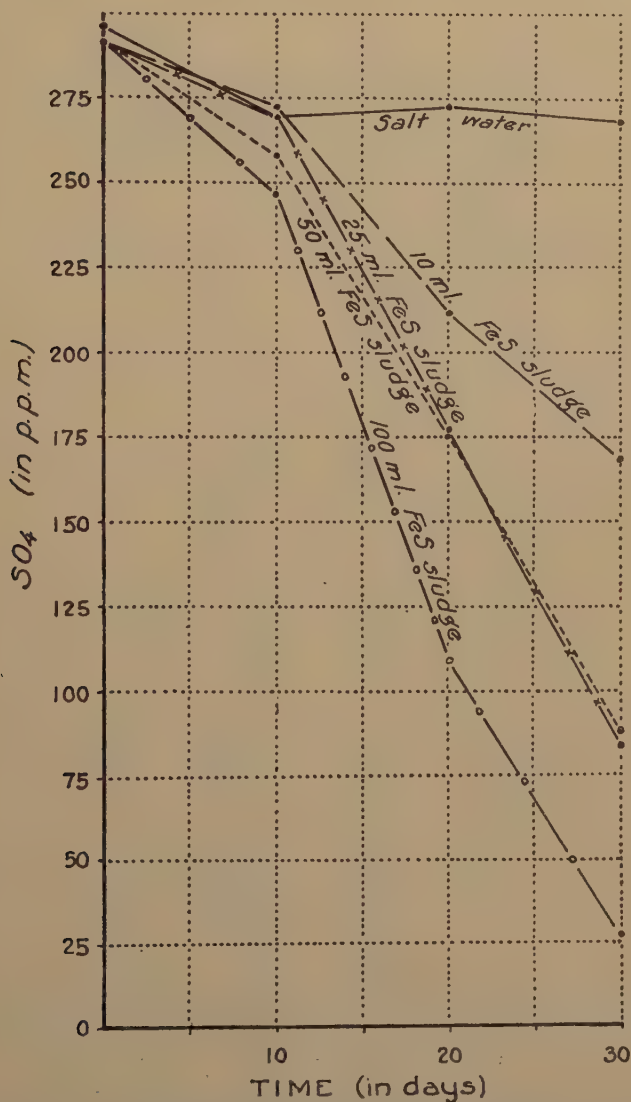


FIG. 6.—EFFECTS DUE TO CHANGES IN VOLUME OF COLLOIDAL FERROUS SULPHIDE SLUDGE ON REDUCTION OF SULPHATES.

effect of different quantities of colloidal ferrous sulphide on the reduction of sulphates, East Texas salt water was

It is apparent from these results that the larger the amount of colloidal ferrous sulphide sludge added, the greater the

sulphate reduction. However, amounts as low as 10 ml. per gallon increase the amount of reduction markedly.

Effect of Bactericides on Reduction of Sul-

These results indicate clearly that phenol, formaldehyde, monochlorobutene, dichlorobutene, trichlorobutane, cresol, Ly-sol, creosote, and thiokol completely

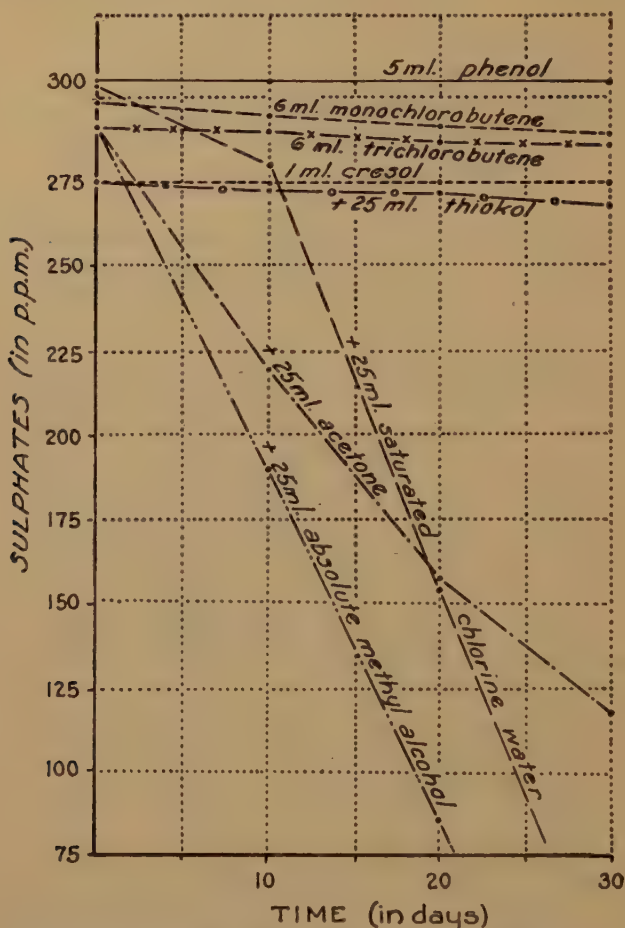


FIG. 7.—EFFECT OF BACTERICIDES ON REDUCTION OF SULPHATES BY BACTERIA.

phates by Bacteria.—Any bactericide or process that will completely kill the sulphate-reducing bacteria will prevent sulphate reduction and hydrogen sulphide formation, as shown by the experiments listed in Table 6, in which the bactericides and iron sulphide sludge were added to the water and the water incubated in 2½-liter bottles at a temperature of 125°F. for 30 days (Fig. 7).

kill the bacteria and prevent the reduction of sulphates and the formation of hydrogen sulphide. On the other hand, saturated chlorine water, alcohol, and acetone do not kill bacteria and do not prevent the reduction of sulphates. Of these various chemicals, the crude cresols are probably the cheapest. In selecting a bactericide for treatment of salt-water disposal, however, it is preferable to use one that

does not itself produce a precipitate in the water. Some of the crude bactericides do this. Pure compounds like formaldehyde, phenol, and cresol do not.

Amounts Required to Treat Salt Water.—

Experiments were carried out in the method described to find the minimum amount of bactericide required to treat $2\frac{1}{2}$ liters of water combined with 25 ml. of colloidal iron sulphide and heated in an incubator for 30 days at 125°F . The results were as follows:

BACTERICIDE	MINIMUM AMOUNT REQUIRED TO PREVENT SULPHATE REDUCTION
Phenol.....	2.5 grams
Formaldehyde.....	0.1 ml.
Lysol.....	2.5 ml.
Cresol.....	1.0 ml.
Monochlorobutene...	3.0 ml.
Trichlorobutane....	3.0 ml.
Creosote.....	7.5 ml.

These results indicate that among the bactericides used in our laboratory to prevent sulphate reduction, cresol and formaldehyde are the most powerful disinfectants; that phenol is a close third, and that monochlorobutene, dichlorobutene, and trichlorobutane are very good, but that larger amounts of the other bactericides are required to be effective.

Method of Applying.—In introducing bactericides into tanks, treaters and disposal systems, it is important to be certain that the substance reaches the partially stagnant places in the tank or disposal system where the bacteria are developing. If the bactericide in small quantities is lubricated into the current of water flowing through the tanks or disposal system, it may be that the chemical will by-pass the stagnant spots and do no good. It is better to make a study of fluid circulation in the system to be treated and to introduce the bactericide into only the stagnant spots. It is also important to streamline tanks and fluid-circulating sys-

tems so that stagnation spots will be eliminated.

ELIMINATION OF HYDROGEN SULPHIDE BY
USE OF FERRIC HYDROXIDE SLUDGE

Sulphate-reducing bacteria are anerobic and do not live or develop well in presence of oxygen and most oxidizing agents (chlorine appears to be an exception). If salt-water systems or separator tank systems for oil-field water could be set up so that the system or tank could be by-passed by the salt-water flow once in 10 days, and thoroughly aerated so that the ferrous sulphide would be oxidized to brown ferric oxide and ferric hydroxide, no sulphate reduction would take place during the next 10 days, or as long as the iron remained in the ferric condition. This can be shown experimentally by placing 50 grams of ferric hydroxide that has been prepared simply by aerating the colloidal ferrous iron sludge in the air along with 50 c.c. of ferrous sulphide in a bottle of East Texas salt water and heating at 125°F . for 30 days in the constant-temperature incubator. No reduction of sulphate or formation of hydrogen sulphide takes place.

TABLE 7.—*Analysis of Oxidized Floc from Bottom of Refuse Pit Used for Holding Sludge Cleaned from Bottoms of Settling Pits, Payne System, Kilgore, Texas*

Constituent	A	B
CaSO_4	2.4	2.0
CaCO_3	29.3	32.6
Fe_2O_3	13.0	12.0
MgCO_3	1.7	1.5
Al_2O_3	4.8	4.9
SiO_2	25.0	10.9
S.....	0.03	?
Organic matter.....	22.1	25.2

A. Analyzed by P. A. Witt.
B. Analyzed by I. W. Walling.

The reason for the bactericidal effect of oxidized ferrous sulphide sludge (ferric hydroxide sludge) and also of thiokol and other rubber compounds on sulphate-

reducing bacteria is not well understood. These mixtures are not known by bacteriologists to be germicidal. The ferrous sulphide was oxidized by heating to 100°C.

sludge might contain antitoxin. However, if this were true, the addition of larger and larger quantities of the unoxidized ferrous sulphide sludge, which presumably carried

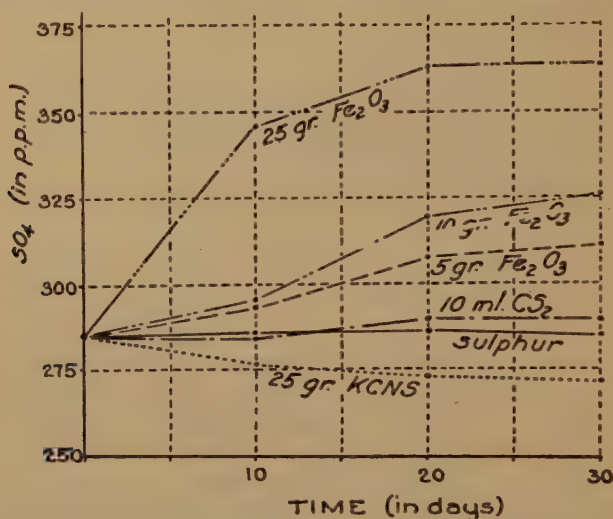


FIG. 8.—EFFECT OF SULPHUR, SULPHUR COMPOUNDS, AND FERRIC HYDROXIDE ON REDUCTION OF SULPHATES BY BACTERIA.

for several hours in a drying oven in the laboratory. Analysis showed that the dried mass contained the ingredients listed in Table 7.

Bacteriologists¹¹ have known for a long time that masses of dead bacteria contain antitoxins or antibodies, which inhibit bacterial growth and prevent development of diseases. Bacteriologists considered that the oxidized and desiccated ferric hydroxide

dead bacteria, ought to decrease instead of increase the sulphate reduction. This is not the result. Furthermore, so far as known, there is no antitoxin in thiokol and rubber. Analyses, however, indicate that rubber compounds contain sulphur and the ferric hydroxide sludge may carry sulphur. Accordingly sulphur and other sulphur compounds were tried out as bactericides for sulphate-reducing bacteria.

TABLE 8.—Effect of Powdered Sulphur and Sulphur Compounds on Reduction of Sulphates by Bacteria*

Material	Concentration of Sulphate				Concentration of H_2S		
	At Beginning	After 10 Days	After 20 Days	After 30 Days	After 10 Days	After 20 Days	After 30 Days
25 grams powdered sulphur.....	285	286	286	285	0.0	0.0	0.0
25 grams potassium sulphocyanide.....	284	277	274	272	2.3	2.5	4.0
10 ml. carbon disulphide.....	284	284	290	290	0.0	0.0	0.0
5 grams oxidized sludge.....	284	293	308	312	0.0	0.0	0.0
10 grams oxidized sludge.....	284	295	320	326	0.0	0.0	0.0
25 grams oxidized sludge.....	284	346	363	364	0.0	0.0	0.0
50 grams oxidized sludge.....	286	346	377	430	0.0	0.0	0.0

* Solution refers to amount added at 2½ liters of brine.

The results are shown in Table 8 and in Fig. 8.

The addition of ferric hydroxide sludge prevents the formation of hydrogen sulphide and may kill or at least inhibit the bacteria. However, it is thought more likely that the ferric oxide reacts with hydrogen sulphide as fast as the sulphide is produced to yield sulphites and sulphates, because the longer the sulphates are incubated with ferric hydroxide the more sulphates are formed (Fig. 8).

APPLICATION OF SULPHATE-REDUCTION TECHNOLOGY TO OIL-FIELD OPERATIONS

The formation of hydrogen sulphide in oil-field waters causes corrosion of iron pipes, tanks, and other equipment and produces black sludges, which clog filters and disposal wells, and have to be cleaned from the bottoms of oil tanks. Hence, prevention of hydrogen sulphide formation is worth undertaking if it can be done economically. The use of bactericides properly injected into water systems and frequent removal or frequent aeration and oxidation of the substances that accelerate bacterial growth promises a solution of this hydrogen sulphide problem in fields like the East Texas field where the hydrogen sulphide is produced by sulphate reduction.

ACKNOWLEDGMENTS

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acknowledged. Mr. P. A. Witt assisted in the experiments with the effect of sulphur and sulphur compounds on sulphate reduction. The work could not have been carried out without the active cooperation of Mr. Harry H. Power, Chairman of the department of petroleum engineering, Mr. Raymond Dawson, director of the Bureau of Engineering Research, and Dr. J. T. Lonsdale, director of the Bureau of Economic Geology, University of Texas, through whose collaboration and permission this paper is submitted for publication.

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Effect of Reservoir Fluid and Rock Characteristics on Production Histories of Gas-drive Reservoirs

BY M. MUSKAT,* MEMBER A.I.M.E. AND M. O. TAYLOR*

ABSTRACT

THEORETICAL calculations have been made on the performance to be expected of gas-drive reservoirs for various characteristics of the oil and gas and the producing rock. Such performance has been expressed graphically as curves for the reservoir pressure and gas-oil ratios of the production as functions of the cumulative oil recovery. The latter has been expressed in terms of percentage of pore space of the reservoir rock. Such curves automatically give values for the ultimate physical recovery, if the latter is interpreted as the recovery obtained when the reservoir pressure has declined to atmospheric, or to any other pressure chosen as defining the state of practical complete depletion.

Calculations of these pressure and gas-oil ratio histories have been made for conditions in which the oil viscosity, the gas solubility and shrinkage, the size of an overlying gas cap, if present, the permeability-saturation characteristics of the rock, and the amount of connate water, have been individually varied. The results serve to show the extent to which the ultimate recoveries are sensitive to the important physical parameters characterizing the oil reservoir.

As is to be expected, the ultimate recoveries are found to decrease with increasing oil viscosity. Because of the predominant effect of the oil shrinkage associated with the liberation of the gas in solution, the ultimate recovery will decrease with increasing gas solubility. Increasing gas-cap volumes lead to higher recoveries, although the contribution made by the gas-cap gas is small as compared with the oil expulsion by the equivalent amount of solution gas.

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* Gulf Research and Development Co., Pittsburgh, Pennsylvania.

As a whole, the oil recovery when expressed in percentage of the pore space is not very sensitive to the details of the permeability-saturation relationship. However, if the rocks possess an equilibrium free-gas saturation, the rise in gas-oil ratio will be retarded, and the ultimate recovery somewhat increased.

The oil shrinkage associated with the liberation of the dissolved gas also leads to the result that as long as the connate water is immobile and the permeability ratio curve for the rock is a function only of the total liquid saturation, the stock-tank oil recovery will be less for a sand containing no connate water than for one with an original water content as high as 30 per cent. The space voidage in the former case will be somewhat greater, but the effect of oil shrinkage will lead to smaller values for the equivalent stock-tank recovery.

These calculations also give data showing how the productivity indexes for the producing wells will vary during the reservoir history. Because of decreasing permeability to the oil and increasing oil viscosity, the productivity index will fall continuously as production proceeds, and may finally reach values as low as 10 per cent of the initial productivity index.

INTRODUCTION

In a previous paper¹ was developed the basic theory for the prediction of the production histories of gas-drive reservoirs. The data required for the application of this theory included the characteristics of the petroleum fluids, such as the viscosity of the oil and gas phases, the solubility of the gas in the oil, and the oil shrinkage—all expressed as functions of the reservoir pressure—and the permeability-saturation characteristics of the producing rock, as

¹ References are at the end of the paper.

defined by the variation of the permeability of the oil and gas phases as functions of the fluid saturations. The theory was illustrated by application to a hypothetical reservoir, at an initial pressure of 2500 lb. per sq. in. (abs.), containing an oil whose viscosity at atmospheric pressure was 1.38 cp., and which had dissolved in it at the initial pressure 534 cu. ft. of gas per barrel, with a shrinkage of 30.8 per cent to atmospheric pressure. In lieu of typical experimental data pertaining to actual reservoirs, the permeability-saturation curves used were those corresponding to the data of Leverett and Lewis² on unconsolidated sands, so adjusted as to imply an equilibrium gas saturation of 10 per cent of the pore space.

The calculations made using these data gave what are recognized to be typical production histories of simple gas-drive reservoirs. The results included curves for the variation of the reservoir pressure and the gas-oil ratio as functions of the cumulative stock-tank oil recovery, which were conveniently expressed in terms of equivalent percentage pore space. As such production histories must of necessity be terminated when the reservoir pressure falls to atmospheric,* except as secondary recovery operations as gas injection or water-flooding might then be instituted, the intercepts of the pressure-decline curves on the recovery axis automatically give the cumulative physical recovery of the system. For a reservoir containing 30 per cent connate water, the recovery so found was equivalent to 14.5 per cent of the pore space. The corresponding free-gas saturation at the time of ultimate depletion was 28.7 per cent of the pore space. While the

former value may seem to be discouragingly low, the latter is actually of the order of magnitude generally accepted heretofore as the free-gas voidage created in most gas-drive oil fields. Even though the recovery would represent 27.1 per cent of the initial stock-tank oil in place, the inherently low displacement efficiency of the gas-drive mechanism was thus confirmed by purely theoretical considerations.

While these general results may well be considered as typical, it is important to ascertain the degree to which they are sensitive to the particular values of the physical parameters that were assumed in the calculations. These, of course, vary over considerable ranges among different oil fields. It is instructive to study how the recoveries and production histories will be affected as the physical characteristics of the fluids and rocks may change from field to field. Accordingly, systematic variations were introduced in the various physical factors involved in the production histories and ultimate recovery calculations.

The particular parameters that were varied included the viscosity of the oil, the gas solubility, oil shrinkage, the magnitude of the initial gas cap, and the permeability-saturation characteristics of the producing formation. For the latter purpose, two types of calculation are reported. In one the reservoir-fluid characteristics were taken as those corresponding to an actual oil-producing field, and the permeability-saturation characteristics of the producing formation were those suggested by the field engineers as the possible limits of variability for the particular producing section in question. In the other, the same permeability-ratio curve was used at low liquid saturations as for the calculations on the effect of viscosity, solubility, etc., but at high liquid saturations the curve was changed to provide for no equilibrium free-gas saturation. In addition, as an indication of the possible effect of the connate water or variation of it, a case where

* While in practice, fields will have to be abandoned before atmospheric pressure is reached, it provides a convenient basis for comparison, and is used throughout the following pages except with respect to the production histories based on Fig. 11. If a limit such as 100 lb. per sq. in. should be preferred, the corresponding recovery data can be read off the pressure-decline curves shown in Figs. 3, 6, 8 and 10.

the connate water saturation was taken as zero was treated.

The basic set of physical data describing the characteristics of the oil and gas,*

hold these other parameters fixed may therefore appear to be quite artificial from a practical point of view. However, the purpose of the calculations was not to

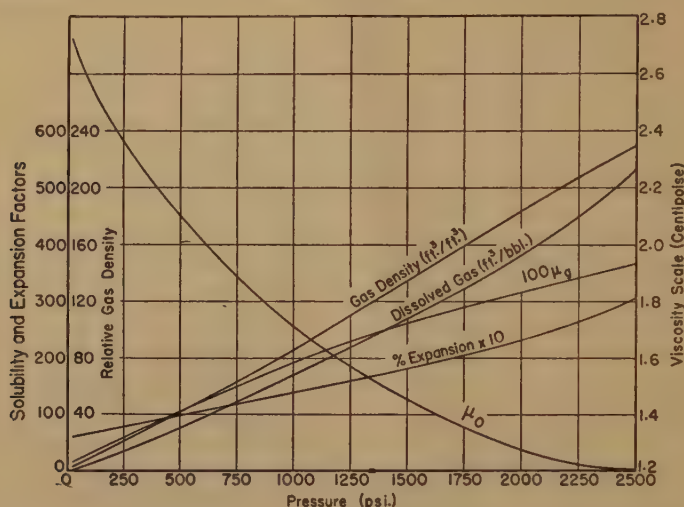


FIG. 1.—PHYSICAL CHARACTERISTICS OF OIL AND GAS, AS FUNCTIONS OF PRESSURE (ABS), ASSUMED IN CALCULATIONS OF RESERVOIR HISTORIES.

μ_o , μ_g are viscosities of oil and gas. Expansion factors are equivalent to $\beta - 1$, and give the oil shrinkage.

which were systematically varied to determine the effect of these parameters on the performance, are plotted in Fig. 1.

EFFECT OF OIL VISCOSITY

In order to establish directly the sole effect of this parameter, the oil viscosity was deliberately changed over the complete pressure range of 2500 lb. per sq. in. (abs.) to atmospheric by constant factors in each case investigated; that is, the original curve of oil viscosity vs. pressure was uniformly multiplied throughout the pressure range by a constant factor, either less than or greater than unity. All other characteristics of the system were held the same. It is recognized, of course, that crude oils of different viscosities generally also show corresponding differences in gas solubility and shrinkage. To deliberately

develop formulas or correlations of recovery vs. the parameters, as might be used directly in practical field operations, but rather to bring out the role played by the separate parameters on the production characteristics. Thus they are intended to show the sensitivity of the reservoir performance to the separate physical parameters rather than to provide absolute values for application to specific cases. Accordingly, for studying the effect of oil viscosity, the viscosity curve shown in Fig. 1 was uniformly multiplied by factors of $\frac{1}{4}$, $\frac{1}{2}$, 1, 2, and 4, and the calculations carried through with these conditions, while the remaining physical variables were kept the same as shown in Fig. 1. The permeability-saturation curve and that for the relative permeability to oil, as used in these calculations, were those shown in Fig. 2,* and

* These are the same data as previously,¹ except that the oil viscosity plotted in Fig. 1 is uniformly twice that assumed before.

* For a total liquid saturation, p_t , less than 0.80, the curve for k_g/k_o in Fig. 2 can be

imply a connate water saturation of 30 per cent. Except for the specific situations discussed on page 13, the solid permeability-ratio curve, implying an equilibrium free gas saturation of 10 per cent, was used throughout.

The basis of these calculations was the nonlinear first-order differential equation, derived in the previous paper, namely:

$$\frac{d\rho_o}{dp} = \frac{\rho_o \lambda(p) + (1 - \rho_w - \rho_o) \epsilon(p) + \rho_o \eta(p) \Psi(\rho_o)}{1 + \frac{\mu_o}{\mu_g} \Psi(\rho_o)} \quad [1]$$

where ρ_o is the reservoir oil saturation at the pressure p , ρ_w is the connate water saturation, the water being considered as immobile, μ_o is the oil viscosity, μ_g the gas viscosity, as functions of the pressure, $\Psi(\rho_o)$ is the ratio of the gas to the oil permeability, as a function of the oil saturation, and as given by Fig. 2, and λ , ϵ and η are functions of the reservoir pressure, defined by:

$$\lambda(p) = \frac{1}{\gamma\beta} \frac{dS}{dp}; \epsilon(p) = \frac{1}{\gamma} \frac{d\gamma}{dp}; \eta(p) = \frac{\mu_o}{\beta\mu_g} \frac{d\beta}{dp} \quad [2]$$

where γ is the density of the free gas within the reservoir compared with that at standard conditions, β is the formation volume of the oil phase, and S is the gas solubility expressed as cu. ft. per cu. ft.

Eqs. 1 and 2 are based on the following representation of the oil-producing reservoir.* The latter is considered as equivalent to a tank with uniformly distributed outlets and at uniform pressure throughout. The gas and liquid phases are assumed to

expressed by:

$$\frac{k_o}{k_a} = 10e^{-20.14(\rho_i - 0.37)}$$

* Essentially the same assumptions and representation were used by E. C. Babson³ and J. Tarnor.⁴ The latter, however, applied the integrated form of the material-balance requirements and had to resort to a trial and error method of solution.

be in continuous equilibrium. The changes in fluid content or withdrawals are related to changes of pressure by material-balance equations expressed in differential form.

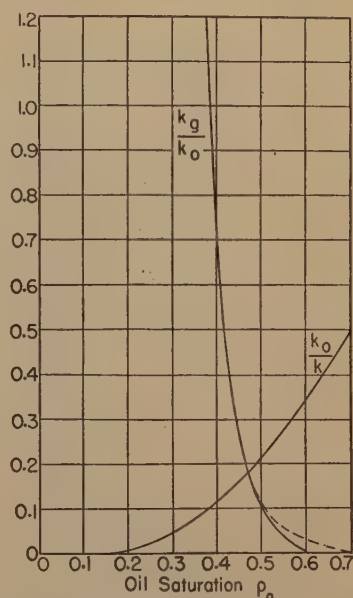


FIG. 2.—PERMEABILITY-SATURATION CURVES USED IN CALCULATIONS OF RESERVOIR HISTORIES. $\Psi(\rho_o) = k_g/k_o$ = (permeability to gas)/(permeability to oil); k_o/k = (permeability to oil)/(homogeneous fluid permeability). Connate water saturation = 30 per cent.

In addition, the producing gas-oil ratio is required to conform to or be consistent with the corresponding state of the fluid saturations, and as implied by the permeability-saturation relationship. As the gas-oil ratio also enters the material-balance conditions it can be eliminated from the two equations, thus leading to Eq. 1 with the notation of Eq. 2.

The cumulative recovery in stock-tank equivalent at any stage of the production history was calculated by the equation:

$$\text{Cumulative recovery, as fraction of pore space} = (\rho_o/\beta)_i - \rho_o/\beta \quad [3]$$

where the subscript i indicates the initial condition.

Eq. 1 was integrated numerically under the conditions indicated above. The results are shown in Figs. 3 and 4. In Fig. 3 are plotted the reservoir pressure and gas-oil

been built up. And $\Psi(\rho_o)$ is 0 during this build-up interval. The terms involving the oil viscosity drop out when $\Psi(\rho_o) = 0$ (Eq. 1), so that the oil viscosity has no

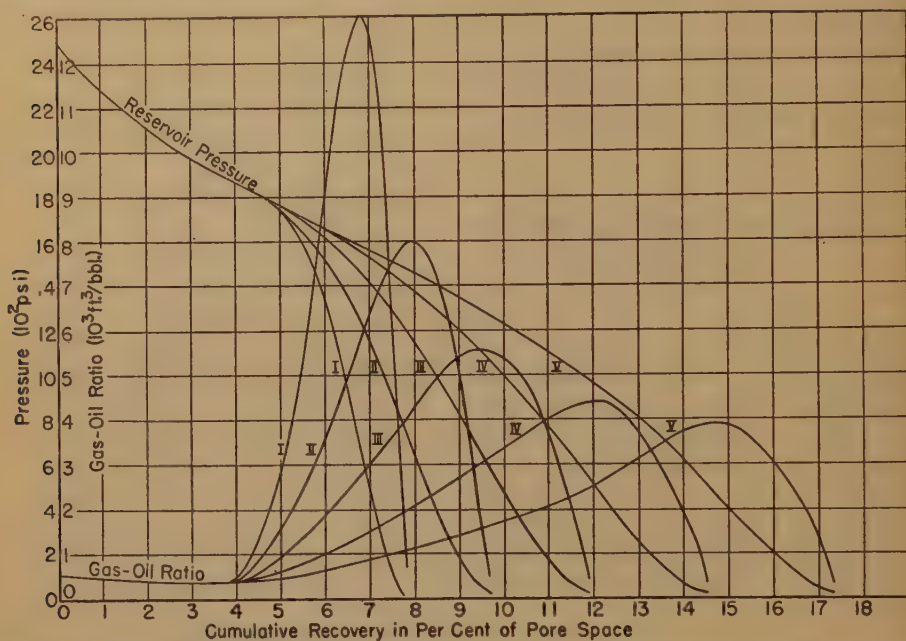


FIG. 3.—PRESSURE AND GAS-OIL-RATIO HISTORIES OF SOLUTION GAS-DRIVE RESERVOIRS PRODUCING OIL OF DIFFERENT VISCOSITIES.

Curve I: atmospheric-pressure viscosity = 11.04 cp.

Curve II: atmos. pres. viscosity = 5.52 cp.

Curve III: atmos. pres. viscosity = 2.76 cp.

Curve IV: atmos. pres. viscosity = 1.38 cp.

Curve V: atmos. pres. viscosity = 0.69 cp.

Gas solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl. in all cases.

ratio histories for the five cases indicated in the legend. It will be seen that, as would be expected, the cumulative recovery increases as the oil viscosity decreases. Accordingly the pressure declines in the later stages of the recovery are more gradual, as are the rises in gas-oil ratio, for the systems of lower viscosity oil. The convergence of the reservoir pressure and gas-oil-ratio curves in the early part of the production history arises from the fact that the equilibrium gas saturation for the gas-permeability curve has been taken as 10 per cent. Accordingly, no free gas will flow until such a free-gas saturation has

effect upon the reservoir pressure and gas-oil-ratio history during this period when expressed as functions of the cumulative recovery. $\Psi(\rho_o)$ first becomes nonvanishing when the reservoir pressure is between 1800 and 1900 lb. per sq. in., so that the spread in the gas-oil-ratio curves develops in this interval. However, because of the step-by-step numerical integration procedure, the divergence in the pressure curves does not become apparent until the pressure actually falls to 1800 lb. per sq. in. In Table 1 are listed the numerical values for the ultimate recovery of stock-tank oil (at atmospheric reservoir pres-

sure) and void space created by the oil expulsion, as well as the maximum gas-oil ratios, for the five systems whose complete histories are shown in Fig. 3. In all cases

curves, which have been so drawn that the space voidage even for infinite viscosity would equal the equilibrium gas saturation, namely 10 per cent.

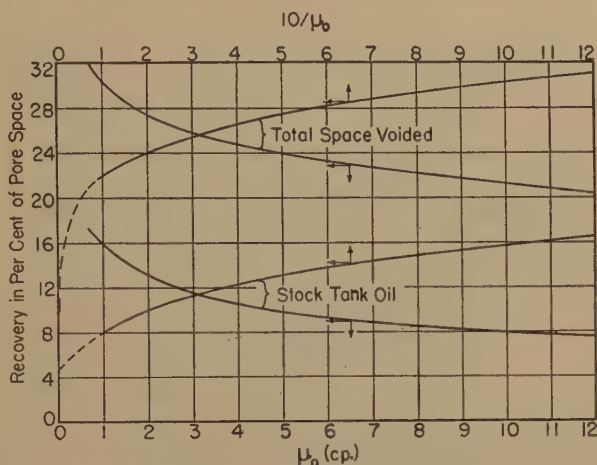


FIG. 4.—RECOVERIES, IN STOCK-TANK OIL AND TOTAL SPACE VOIDED, OF GAS-DRIVE RESERVOIRS AS FUNCTIONS OF THE OIL VISCOSITY.

μ_0 = atmos. pres. oil viscosity.

Gas solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl.

Shrinkage from 2500 lb. per sq. in. = 30.8 per cent.

the gas solubility at 2500 lb. per sq. in. (abs) was 534 cu. ft. per bbl., and shrinkage from 2500 lb. per sq. in. was 30.8 per cent.

TABLE 1.—Ultimate Recovery of Stock-tank Oil

Viscosity at Atm. Pres., Cp.	Stock-tank Recovery, Per Cent Pore Space	Ultimate Space Voidage, Per Cent Pore Space	Recovery, Per Cent Initial Oil	Maximum Gas-oil Ratio, Cu. Ft. Per Bbl.
0.69	17.32	31.74	32.36	3,900
1.38	14.48	28.73	27.06	4,400
2.76	11.86	25.97	22.16	5,600
5.52	9.65	23.63	18.03	8,000
11.04	7.79	21.66	14.56	13,100

The recovery values as listed in this table are plotted in Fig. 4 against the viscosity and the reciprocal of the viscosity. The latter permits some degree of extrapolation to cases where the oil viscosity may be considerably higher than covered by the calculations. This extrapolation is indicated by the dashed segments of the

It will be seen from both Table 1 and Fig. 4 that the space voidage variation is essentially parallel to that of the stock-tank recovery and is of the order of twice the latter. In terms of the absolute variation, it will be noted that the stock-tank recovery will vary by a factor of 2 for a range of viscosity variation of 1 to 10 cp. It is clear, therefore, that recovery factors as frequently applied in the evaluation of oil-producing formations cannot be used indiscriminately without regard to the viscosity of the oil to be produced.

In addition to predictions regarding the pressure and gas-oil-ratio histories and ultimate recoveries, the integration of Eq. 1 also provides information on the variation of the productivity indexes of the producing wells during the production history. Such variation is that due to the decrease in oil permeability and formation-volume factor of the oil and increase in oil viscosity, as the pressure and residual oil

saturation decline. Because local well conditions may differ from those in the reservoir as a whole, the absolute values of calculated productivity indexes would

diverge, the decline with cumulative recovery is more rapid for the more viscous oil, though the ultimate values reached are least for the oil of lowest viscosity. This,

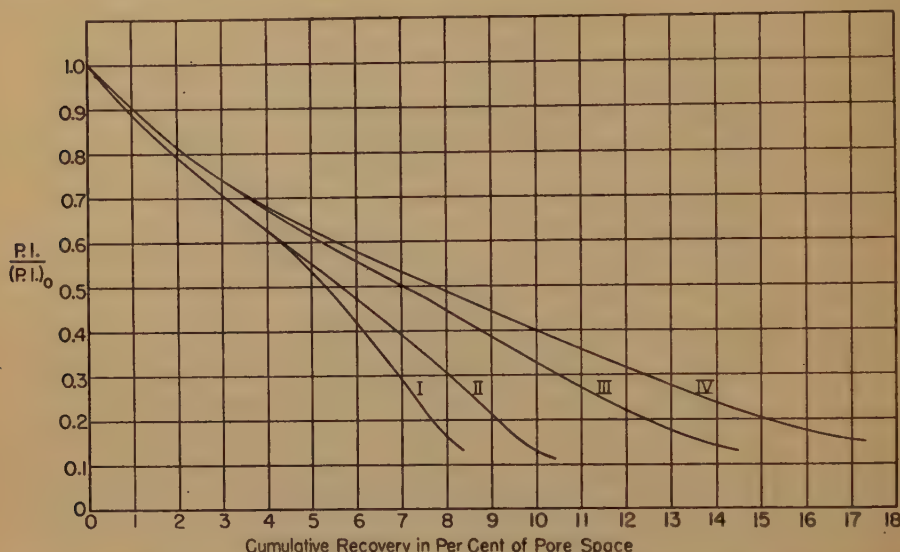


FIG. 5.—HISTORIES OF PRODUCTIVITY INDEX VARIATIONS IN GAS-DRIVE FIELDS PRODUCING OILS OF DIFFERENT VISCOSITIES.

$(PI)/(PI)_0$ = (current productivity index)/(initial productivity index).

Curve I: μ_o (atmos. pres.) = 11.04 cp.

Curve II: μ_o (atmos. pres.) = 5.52 cp.

Curve III: μ_o (atmos. pres.) = 2.76 cp.

Curve IV: μ_o (atmos. pres.) = 1.38 cp.

Curve V: μ_o (atmos. pres.) = 0.69 cp.

probably not be accurate. However, the relative magnitudes of the productivity index, as compared with their initial values, should be given by the calculations with reasonable accuracy, provided the well is representative of the field as a whole. These relative values of the productivity

index, defined by the ratio $\frac{k_o/\mu_o\beta^*}{(k_o/\mu_o\beta)_i}$, are plotted in Fig. 5 for the five cases listed in Table 1. Here, again, the curves coincide until the equilibrium gas saturation (10 per cent) is built up, during which period the production histories are independent of the oil viscosity. When they do begin to

of course, is due to the lower residual oil saturation, and hence smaller oil permeability for the low-viscosity oil. It should also be noted that while Fig. 5 indicates a very material drop in productivity index due only to the changes in oil viscosity and shrinkage, the total potentials of the wells will be still further reduced because of the decline in reservoir pressure and total pressure differentials available for producing the oil.

EFFECT OF GAS SOLUBILITY

As in the study of the effect of oil viscosity, the role played by the gas solubility was investigated by keeping the other variables fixed while permitting the solubil-

* These refer to the limiting values at zero pressure differential.

ity to change. This assumption, too, is basically arbitrary, and it is recognized that with the varying gas solubility are generally associated different gravities and

represented by the last two rows were investigated.

As before, the changes in solubility or shrinkage listed in Table 2, and which refer

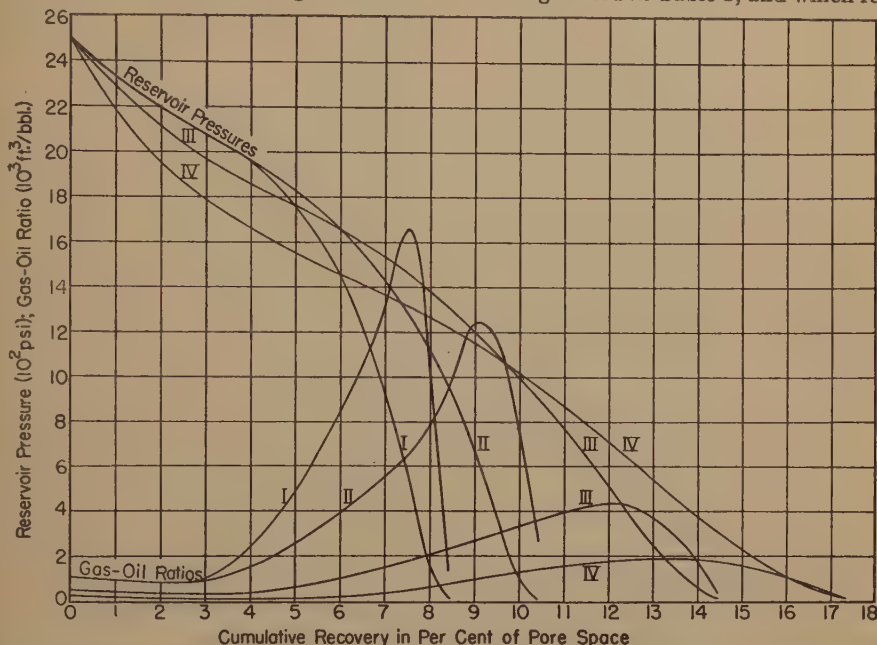


FIG. 6.—PRESSURE AND GAS-OIL HISTORIES OF SOLUTION GAS-DRIVE RESERVOIRS PRODUCING OIL OF DIFFERENT GAS SOLUBILITIES AND VISCOSITIES.

Curve I: gas solubility at 2500 lb. per sq. in. = 1068 cu. ft. per bbl.; atmos. pres. viscosity = 2.76 cp.; shrinkage from 2500 lb. per sq. in. = 61.6 per cent.

Curve II: same as curve I except that atmos. pres. viscosity = 1.38 cp.

Curve III: gas solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl.; atmos. pres. viscosity = 1.38 cp.; shrinkage from 2500 lb. per sq. in. = 30.8 per cent.

Curve IV: gas solubility at 2500 lb. per sq. in. = 267 cu. ft. per bbl.; atmos. pres. viscosity = 1.38 cp.; shrinkage from 2500 lb. per sq. in. = 15.4 per cent.

viscosities of the crude. On the other hand, for three of the cases treated, the shrinkage was allowed to vary simultaneously with the solubility. In particular, it was assumed that the shrinkage was directly proportional to the solubility, as a first approximation. Accordingly, Eq. 1 was integrated under the conditions listed in the first three columns of Table 2. The second row refers to the case previously listed in the second row of Table 1. To obtain an additional check on the effect of the viscosity, the case represented by the fourth row was also treated. And to bring out more explicitly the effect of oil shrinkage, the systems

directly to the values at 2500 lb. per sq. in., were applied uniformly over the whole pressure ranges to the original curves shown in Fig. 1. As mentioned, these changes were arbitrarily imposed even though the other physical parameters as well as the initial reservoir pressure were taken as fixed.

The production and gas-oil-ratio histories for the first four cases listed in Table 2 are plotted in Fig. 6. Qualitatively these curves show the same characteristic features as those in Fig. 3. Here, too, for curves 1 and 2 (rows 4 and 3 of Table 2), in which only the viscosity was varied, the

initial parts of the pressure and gas-oil-ratio curves are coincident, and diverge only after the equilibrium free-gas saturation has been developed. On the other hand,

TABLE 2.—*Effect of Gas Solubility*

Solubility at 2500 Lb. per Sq. In., Cu. Ft. per Bbl.	Atmospheric Pressure, Viscosity Cp. ^a	Shrinkage from 2500 Lb. per Sq. In., Per Cent	Stock-tank Recovery, Per Cent Pore Space	Ultimate Space Voidage, Per Cent Pore Space	Recovery, Per Cent Initial Oil	Maximum Gas-oil Ratio, Cu. Ft. per Bbl.
267	1.38	15.4	17.33	25.44	28.57	1,900
534	1.38	30.8	14.48	28.73	27.06	4,400
1,068	1.38	61.6	10.44	33.37	24.10	12,500
1,068	2.76	61.6	8.41	31.11	19.41	16,600
1,068	1.38	30.8	17.16	31.57	32.06	9,400
534	1.38	0	26.85	26.85	38.36	3,150

^a Except for the fourth row, the viscosities were uniformly taken as half those shown in Fig. 1.

where the curves differ in gas solubility and shrinkage, both the gas-oil ratio and pressure histories diverge from the very beginning. This, of course, is because the gas evolution and shrinkage of the residual oil will affect immediately the pressure equilibrium conditions whether or not the free gas phase is mobile. It is also interesting to observe that although ultimately the reservoir-pressure curve 4 (row 1 of Table 2), with the least gas solubility, flattens out and indicates a higher recovery than pressure curve 3 (row 2 of Table 2), it shows a more rapid initial decline. The cause of this, evidently, is that in the early stages of production the oil with low dissolved gas content must suffer a greater pressure decline to release sufficient gas to supply the voidage for the oil expulsion than when the gas solubility is high, and only a moderate pressure drop will permit a high degree of gas liberation.

Perhaps the most striking result shown by these calculations is that the stock-tank recovery increases as the gas solubility decreases for the first three cases listed in Table 2. This apparent anomaly is readily

explained, however, on recalling that in these calculations the shrinkage was made proportional to the total solubility; in fact, it is really the shrinkage that is the most significant factor in leading to these results. To emphasize this point, the cases represented by the last two rows in Table 2 were treated. In the first of these the shrinkage was kept the same as for a gas solubility of 534 cu. ft. per bbl.; i.e., 30.8 per cent. In the second, the shrinkage was deliberately assumed to be zero.

The ultimate free-gas saturation developed for a solubility of 1068 cu. ft. per bbl. and shrinkage of 30.8 per cent is slightly less than that indicated by the third row for an oil with the same viscosity and gas solubility and a shrinkage of 61.6 per cent. However, the stock-tank recovery was 64 per cent greater than in the latter case, and the recovery in percentage of the initial oil in place was 33 per cent greater. For the extreme conditions of the last row for which zero shrinkage was assumed, the contrasts are even more pronounced. It appears, therefore, that while a minimum amount of gas is certainly necessary to provide for the basic mechanism of oil expulsion in a gas-drive reservoir, any additional solution gas beyond such a minimum will generally tend to lessen the recovery because of the greater shrinkage in the residual oil and in the oil produced, which results from the gas liberation. This is further brought out on observing from Table 2 that the ultimate free-gas voidage varies but little for the various cases studied.* It is in the translation of this ultimate space voidage into the equivalent stock-tank recovery that the oil shrinkage plays the dominant role, and directly leads to the lower recoveries for the higher solubility and higher shrinkage oils.

These results could even have been anticipated by inspection of the expression

* In the first three rows of Table 2 the space voidage even increases while the stock-tank recovery decreases.

for the ultimate recovery in terms of the residual fluid saturations; namely,

Ultimate recovery, as fraction of pore space

$$= \frac{1 - \rho_w}{\beta_i} - \frac{(1 - \rho_w - \rho_{ga})}{\beta_a} \quad [4]$$

stock-tank oil at all. This was actually observed on integrating Eq. 1 for an oil of 267 cu. ft. per bbl. initial solubility while retaining a shrinkage value of 30.8 per cent, which previously had been associated

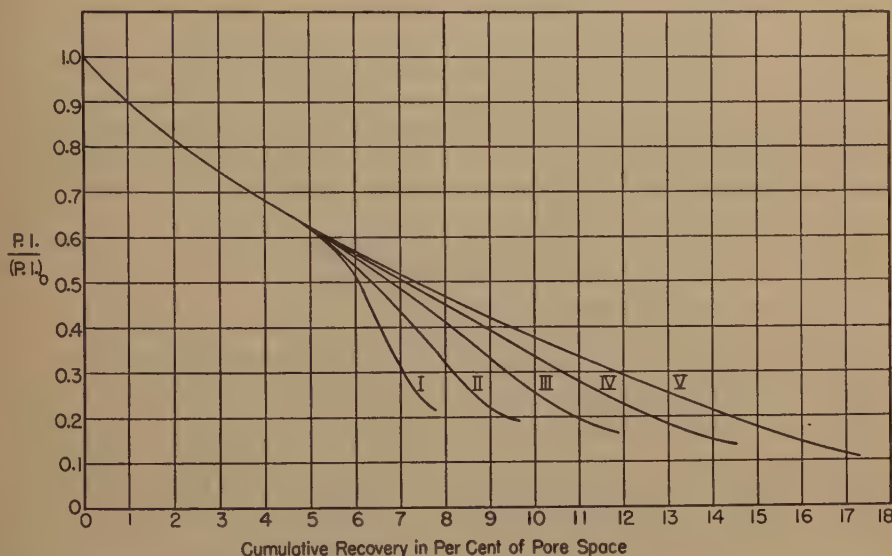


FIG. 7.—HISTORIES OF PRODUCTIVITY INDEX VARIATIONS IN GAS-DRIVE FIELDS PRODUCING OIL WITH DIFFERENT GAS SOLUBILITIES.

$(PI)/(PI)_0$ (current productivity index)/(initial productivity index).

Curve I: solubility at 2500 lb. per sq. in. = 1068 cu. ft. per bbl.; shrinkage = 61.6 per cent; atmos. pres. viscosity = 2.76 cp.

Curve II: same as curve I except that atmos. pres. viscosity = 1.38 cp.

Curve III: solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl.; shrinkage = 30.8 per cent; atmos. pres. viscosity = 1.38 cp.

Curve IV: solubility at 2500 lb. per sq. in. = 267 cu. ft. per bbl.; shrinkage = 15.4 per cent; atmos. pres. viscosity = 1.38 cp.

where β_i is the initial formation-volume factor ($1 + \text{shrinkage}$), β_a is that of the residual oil at atmospheric pressure, and ρ_{ga} is the ultimate free-gas saturation. As the latter varies but slowly with the shrinkage, the predominant factor is therefore β_i . Thus, if ρ_{ga} be taken as 0.30, ρ_w as 0.30, and β_a as 1.05, Eq. 4 will predict zero recovery if the initial shrinkage exceeds 84 per cent. In fact, even in the early history of a reservoir, if the saturated oil has a sufficiently high shrinkage there will ultimately develop a pressure decline associated with an equilibrium bleeding off of the gas within the pore space without any removal of

with a solubility of 534 cu. ft. per bbl. While the material-balance requirements for a drop in pressure from 2500 to 2400 lb. per sq. in. could be satisfied by a reduction in oil saturation of 0.77 per cent, the stock-tank oil equivalent of the lower oil saturation was even greater than its initial value. Of course, with actual crude oils and their natural gases, the occurrence of such extreme situations is very unlikely. However, it may well be anticipated that as the result of differences in the crude-oil shrinkage, the observed gas-drive recoveries will show a very material range of variation.

The variation of the relative productivity

indexes with cumulative recovery is plotted in Fig. 7 for the first four cases listed in Table 2. As in the case of Fig. 5, the productivity indexes will ultimately fall to 10 to 15 per cent of their initial values, the absolute magnitudes being determined largely by the free-gas saturation and the reduced oil permeabilities.

EFFECT OF A GAS CAP ON THE PERFORMANCE OF GAS-DRIVE RESERVOIRS

Although Turner⁴ has treated the problem of the production histories of gas-drive reservoirs overlain by gas caps, it will also be discussed here for the sake of completeness. The general method of solving such problems is based on the integration of a differential equation; namely,

$$\frac{d\rho_o}{dp} = \frac{\rho_o \lambda(p) + \{H(1 - \rho_o - \beta \bar{\rho}_{oi}) + 1 - \rho_w - \rho_o\} \epsilon(p) - H \frac{\bar{\rho}_{oi}}{\gamma} \frac{d\beta}{dp} + \Psi \rho_o \eta(p)}{1 + \frac{\mu_o}{\mu_g} \Psi} \quad [5]$$

where H is a ratio of the original gas-cap zone to the oil-saturated zone, and $\bar{\rho}_{oi}$ is the residual oil saturation in the gas cap expressed in stock-tank equivalent. The other symbols have the same meanings as in Eq. 1. Eq. 5 is based on the assumption that the connate water in the gas cap is the same as in the oil zone, that the oil in the gas cap is immobile, and finally that the size of the gas cap, as expressed by H , remains the same throughout the production history.* The depletion of the gas cap thus takes place by diffusion throughout the oil zone, and its gas content will ultimately be produced with the oil and gas from the oil-saturated state. H is equal to

* While it is recognized that, in general, the size of initial gas caps will not remain strictly fixed, this simplifying assumption should not invalidate the relative effect of gas-cap size derived here. Moreover, to take into account a possible gas-cap expansion, it is necessary to introduce assumptions regarding the residual oil in the expanded region, which may involve uncertainties as serious as that arising from the assumption that H is constant.

what is frequently termed the m factor in material-balance calculations.

Using the same basic reservoir fluid and permeability data as before, Eq. 5 was integrated for the values of H equal to 0.20, 0.40, 0.70, and 1.00. The oil saturation in the gas cap, $\bar{\rho}_{oi}$, was taken as zero. The complete pressure-decline and gas-oil-ratio histories are plotted in Fig. 8. The specific values of the ultimate recoveries and maximum values of the gas-oil ratios are listed in Table 3, including the case of zero gas cap. The value of ultimate stock-tank recovery, and corresponding values of ultimate space voidage, are plotted as a function of H in Fig. 9.

TABLE 3.—Ultimate Recoveries and Maximum Gas-oil Ratios

H	Stock-tank Recovery, Per Cent Pore Space	Ultimate Space Voidage, Per Cent Pore Space	Recovery, Per Cent Initial Oil	Maximum Gas-oil Ratio, Cu. Ft. per Bbl.	Total Gas Available, Cu. Ft. per Bbl. Pore Space of Oil Zone
0	11.86	25.97	22.16	5,600	286
0.20	14.05	28.28	26.25	9,300	466
0.40	15.49	29.80	28.94	12,700	647
0.70	16.81	31.20	31.41	19,500	918
1.00	18.08	32.54	33.78	24,300	1189

It will be seen, as Turner also found, that the gas cap will contribute to the ultimate recovery. For values of H greater than 0.5, the increase in both the stock-tank recovery and space voidage is almost linear, an increase in H of 0.25 leading to an additional stock-tank recovery of 1 per cent and a space voidage increase of 1.1 per cent, expressed in terms of pore space. As is to be expected, the gas-oil ratios will be greater for the higher values of H . It is clear from these results that, in order to achieve maximum recovery from gas-drive reservoirs, it is necessary to avoid bleeding of the gas caps, if any are present, and to force the free gas to flow through the oil zone so as to assist the solution gas in the oil expulsion.

The last column of Table 3 gives the total

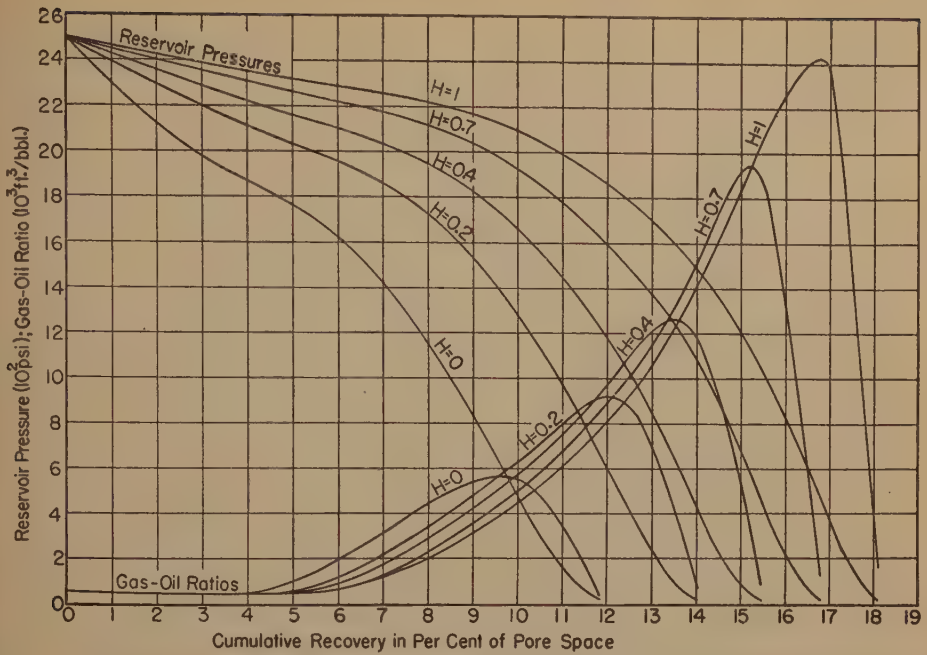


FIG. 8.—RESERVOIR PRESSURE AND GAS-OIL RATIO HISTORIES OF GAS-DRIVE RESERVOIRS WITH VARIOUS THICKNESSES OF GAS CAP.

H = (thickness of gas cap)/(thickness of oil zone); gas solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl.; shrinkage from 2500 lb. per sq. in. = 30.8 per cent; atmos. pres. viscosity = 2.76 cp.

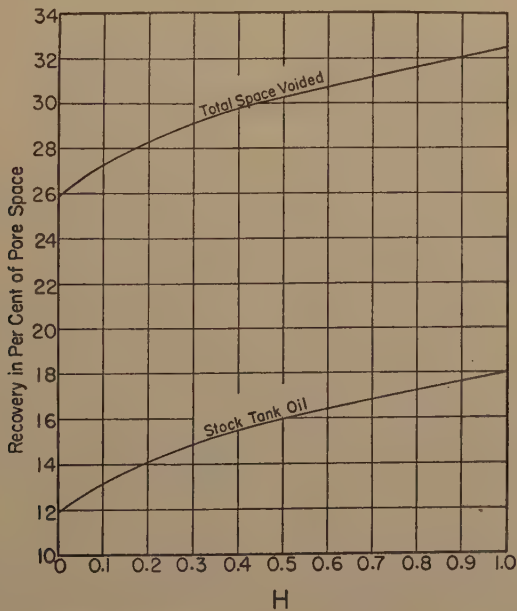


FIG. 9.—RECOVERIES, IN STOCK-TANK OIL AND TOTAL SPACE VOIDED, OF GAS-DRIVE RESERVOIRS AS FUNCTIONS OF GAS-CAP THICKNESS.

H = (gas-cap thickness)/(oil zone thickness).

gas available in both the oil zone and gas cap, per barrel of pore space in the oil section. While the gas in the gas cap does lead to additional recovery, the increase is achieved very inefficiently; thus, whereas the 286 cu. ft. in the oil pay itself will lead to a recovery of 11.86 per cent, increasing the available gas by a factor of 4 will lead to only 6.2 per cent more recovery. On the other hand, in terms of the recovery without the gas cap, the increase due to utilization of the gas cap gas will be of great practical value.

EFFECT OF VARIATIONS IN PERMEABILITY-SATURATION RELATIONSHIP ON THE PRODUCTION PERFORMANCE

Because of the difficulty of obtaining precise data on permeability-saturation relationships for actual cores, and the uncertainty regarding the proper method of averaging them when they are different for the various samples from a given stratum, it is of value to determine the sensitivity of the production performance and ultimate recoveries to the exact form that is used for the permeability-saturation curve. Accordingly, a change was made deliberately in the permeability-ratio saturation curve used for the previous calculations, and the computations were repeated. This change is indicated by the dashed curve in Fig. 2, so as to see what would happen if there were no equilibrium free-gas saturation of 10 per cent, as implied by the continuous solid curve. Beyond 48 per cent oil saturation the values of the permeability ratios were taken to be the same as before. Again, the properties of the reservoir fluids were assumed to be those shown in Fig. 1.

The pressure and gas-oil-ratio histories for this system are plotted in Fig. 10. For comparison, the previously derived results using the solid continuous permeability curve of Fig. 2 are also plotted. The ultimate recovery is definitely less for the modified curve than for that with the equilibrium free-gas saturation. With this result is to be associated the more rapid

rise* in gas-oil ratio which, in turn, suppresses the maximum value developed throughout the production history. While, in terms of percentage of pore space, the reduction in ultimate recovery is not large—namely, 1.46 per cent—in terms of actual barrels of oil recovered from practical oil-producing reservoirs, the difference may be quite significant.

In order to evaluate the effect of variations in the permeability-saturation relationship at low liquid saturations, data were used from an actual oil-producing reservoir. Calculations were made with three different permeability-saturation curves (Fig. 11). While they are plotted here only to values of the permeability ratio as low as 0.001, the curves were extrapolated to 0 at 100 per cent liquid saturation. Curves I and II coincide in the region of high saturations, and diverge only for saturations less than 82 per cent. Curve III differs from the other two throughout the complete saturation range plotted. The reservoir pressure was 1727 lb. per sq. in., at which the gas solubility was 758 cu. ft. per bbl. The shrinkage to atmospheric pressure was 36.0 per cent. Moreover, the atmospheric-pressure viscosity of the oil was 2.4 cp. The connate water saturation was taken as 20 per cent and, on the basis of independent evidence, the field was assumed to have an initial gas cap corresponding to $H = 0.54$. The most significant results of the calculations are listed in Table 4.

As would be expected, curve II of Fig. 11, which rises more rapidly at low saturations than curve I, leads to a somewhat lower recovery than curve I. In actual magnitude, however, the difference is rather small. On the other hand, curve III, which shows a smaller divergence from curve II at low saturations, but was considerably higher than both curves I and II at high saturations, gave a somewhat greater reduction in the ultimate recovery. The

* In fact, as in all other previous gas-oil ratio curves, the gas-oil ratio shows an initial decline when the equilibrium free-gas saturation is nonvanishing.

major contribution to this reduction arises from the differences in the curves at high liquid saturations. This is borne out by the computation of the complete gas-oil-

from the previous calculations, that in terms of percentage of the pore space the ultimate recovery will not be very sensitive to the details of the permeability-satura-

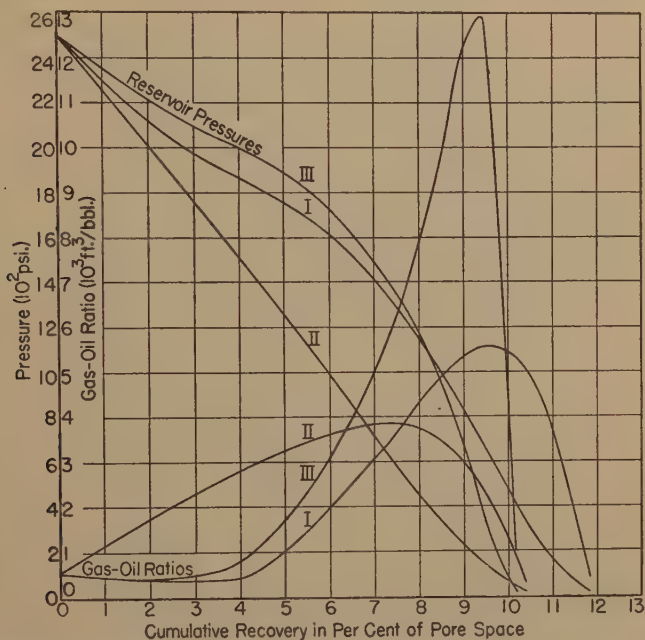


FIG. 10.—RESERVOIR PRESSURE AND GAS-OIL-RATIO HISTORIES OF SOLUTION GAS-DRIVE RESERVOIRS.

Curve I: permeability-ratio curve used was solid curve of Fig. 2.

Curve II: permeability-ratio curve used was dashed curve of Fig. 2.

Curve III: zero connate water saturation. Gas solubility at 2500 lb. per sq. in. = 534 cu. ft. per bbl.; shrinkage from 2500 lb. per sq. in. = 30.8 per cent, and atmos. pres. oil viscosity = 2.76 cp. for all curves.

Connate water saturation = 30 per cent for curves I and II.

TABLE 4.—Effect of Variations

Permeability-ratio Curve of Fig. II	Stock-tank Recovery to 100 Lb. per Sq. In., Per Cent Pore Space	Space Voidage, to 100 Lb. per Sq. In., Per Cent Pore Space	Recovery, Per Cent Initial Oil	Maximum Gas-oil Ratio, Cu. Ft. per Bbl.
I	16.70	33.26	28.40	14,800
II	16.19	32.69	27.53	16,500
III	15.46	31.88	26.29	15,500

ratio curve, which shows a much more rapid initial rise in gas-oil ratio when using curve III and, hence, a correspondingly lower maximum value of gas-oil ratio. As a whole, it appears from these, as well as

tion curve that is used. On the other hand, even the small differences that would be predicted on the basis of the different permeability-saturation curves may still represent significant amounts of actual oil production.

EFFECT OF CONNATE WATER

To get some measure of the effect of the connate water saturation on the production performance and ultimate recovery, calculations were made for a system in which the connate water saturation was arbitrarily taken to be zero. All the other physical properties involved were left as before. The permeability-saturation relationship was taken to be as shown by the solid curve

in Fig. 2 except that it was shifted by 0.30 on the abscissa scale to give equivalent values of the total liquid saturation. The work of Leverett and Lewis has indicated

percent connate water. Initially the pressure decline is slower for the sand completely saturated with oil, owing evidently to larger amounts of gas available for liber-

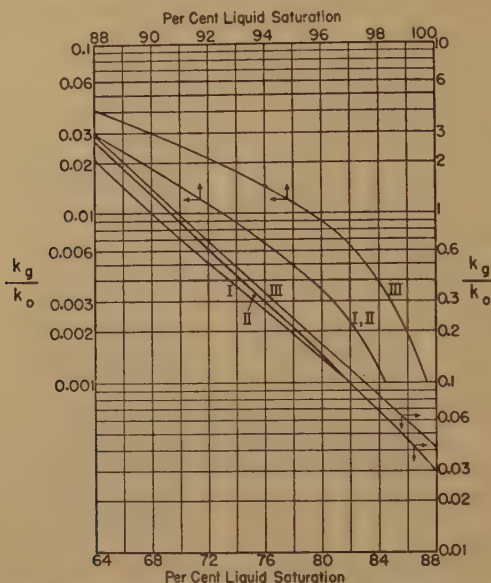


FIG. 11.—TYPES OF PERMEABILITY-SATURATION CURVE USED TO STUDY THEIR EFFECT ON PRODUCTION HISTORIES OF GAS-DRIVE RESERVOIRS.

$$k_g/k_o = (\text{permeability to gas})/(\text{permeability to oil}).$$

that for moderate values of water saturation the ratio of gas to oil permeability is a function only of the total liquid saturation. This means, for example, that $\frac{k_g}{k_o}$ is the same for an oil saturation of 50 per cent with a connate water saturation of 30 per cent as for the case where the sand has no water and the oil saturation is 80 per cent.

The pressure decline and gas-oil-ratio histories for the present case are shown as curve III in Fig. 10. It will be recalled that curve I of Fig. 10 refers to exactly the same conditions as curve III except for the presence of 30 per cent connate water. Surprising as it may seem, the ultimate recovery for the system with no water saturation, and hence more reservoir oil and also containing more gas in solution, is less by 1.7 per cent in terms of pore space, or 14 per cent in terms of actual recovery, than for the case where the pay had 30

per cent connate water. Initially the pressure decline is slower for the sand completely saturated with oil, owing evidently to larger amounts of gas available for liber-

ation and displacement of the oil produced in the early life of the production history. Ultimately, however, the pressure begins to fall more steeply and, finally, reaches atmospheric pressure at a recovery less than if the pay had 30 per cent connate water. The basic reason for this apparently anomalous result is to be found in the increased shrinkage provided by the greater volume of reservoir oil in the sand containing no connate water. In fact, the ultimate space voidage, with no connate water, is even 4 per cent greater than with 30 per cent connate water; that is, 29.96 as against 25.97 per cent. However, the contribution to this space voidage due merely to shrinkage is so great that the actual stock-tank oil expulsion is even less than when one starts with a smaller volume of reservoir oil.

This general effect can also be antic-

ipated from Eq. 4, because when the derivative of Eq. 4 is taken with respect to ρ_w a positive value $\frac{1}{\beta_a} - \frac{1}{\beta_i}$ is obtained, thus showing directly that to a first approximation wherein the ultimate space voidage ρ_{ga} is taken as fixed, the recovery will increase with increasing water content. Moreover, the magnitude of this rate of increase is determined by the relative shrinkage from the initial reservoir pressure to that at atmospheric pressure.

It thus appears that, from the point of view of recoverable reserves, the presence of immobile connate water in a formation may aid the recovery, at least indirectly, rather than be detrimental to it. On the other hand, such a conclusion refers only to the gas-drive type of reservoir. Evidently, under conditions in which gravity drainage can be an important factor, or where natural water drives or water-flooding may control the production performance, the presence of connate water will reduce the recoverable reserves so that they will reduce the original stock-tank equivalent of the reservoir oil in place.

CONCLUSIONS

The results discussed in this paper lead to the following conclusions:

1. The ultimate recovery of gas-drive fields is quite sensitive to the oil viscosity. For a variation in oil viscosity at atmospheric pressure and reservoir temperature over the range of 1 to 10 cp., the stock-tank recovery will decrease by a factor of 2, provided all other physical characteristics of the system are kept fixed and the viscosity variations with pressure are similar.

2. While the increased solution gas in a crude will in itself tend to favor greater ultimate recoveries, the associated increased oil shrinkage will generally result in lower stock-tank recoveries.

3. Oil reservoirs overlain by gas caps will have greater recoveries if the gas-cap gas is not bled off, but is forced to diffuse

through and be produced with the oil from the oil zone. However, the additional gas provided by the gas cap is less effective in oil expulsion than the original dissolved gas content of the oil.

4. The ultimate recoveries of gas-drive reservoirs in terms of percentage of pore space are not very sensitive to the details of the permeability-saturation curve. Permeability-ratio curves that provide for no equilibrium gas saturation will lead to a rapid growth of the gas-oil ratio, and lower recoveries than in systems having a definite equilibrium gas saturation. As a whole, the ultimate recoveries are more sensitive to the nature of the permeability-ratio curve at high liquid saturations than to its variations at lower liquid saturations.

5. Because of the smaller shrinkage effect associated with the reservoir oil in rocks containing appreciable amounts of connate water, the recoveries will be greater than if the same rocks contained no connate water and were fully saturated with oil. The ultimate void space with no connate water will be somewhat greater, but the equivalent stock-tank oil recovery will be less.

6. The ultimate space voidage created by oil expulsion is in general less sensitive to variations in the physical parameters of the fluid and rocks than is the stock-tank recovery.

7. Because of the decreased permeability to the oil after the oil saturation declines, and its increased viscosity as it loses its solution gas, the productivity indexes of wells in gas-drive fields will continuously fall. The final value reached will depend upon the ultimate recovery and atmospheric-pressure viscosity of the oil, and may be as low as 10 per cent of its initial value.

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The Viscosity of Air, Water, Natural Gas, Crude Oil and Its Associated Gases at Oil Field Temperatures and Pressures

By CARLTON BEAL,* JUNIOR MEMBER A.I.M.E.

(Los Angeles Meeting, October 1945; Chicago Meeting, February 1946)

ABSTRACT

THIS paper presents useful charts for conversion of various viscosimeter units into centipoises and graphically summarizes published investigations of the viscosity of air, water and natural gas at high temperatures and pressures. Where possible, charts and correlations were constructed to cover a range of temperature (60°F. to 300°F.) and pressure (14.7 lb. per sq. in. abs. to 8000 lb. per sq. in. gauge) encountered in oil fields.

Correlation charts, for the purpose of predicting crude oil viscosity and solubility behavior at oil field temperatures and pressures, were constructed from an analysis and correlation of 1332 viscosity and solubility observations from 953 crude oil samples taken from 747 oil fields. Of these fields, 501 are in the United States, including 75 in California. Of the 1332 observations, 1215 were viscosity values, including 786 of gas-free crude oil, 351 of oil saturated with gas, and 78 undersaturated with gas at pressures above the bubble point.

Results show that crude oil viscosity at various reservoir conditions can be predicted with average deviations varying from 24.2 per cent for gas-free crude oil to as little as 2.7 per cent for undersaturated crude oil "above the bubble point." The solubility of crude oil may be predicted from oil gravity and saturation pressure with an average deviation of 22.0 per cent from observed values. In conclusion, it is shown that the viscosity of a gas and gas-saturated crude oil may be predicted within the accuracy of most reservoir computations.

INTRODUCTION

Viscosity is a measure of flow resistance; common units are in centipoises (cp.). The object of this report is to present conversion charts and simplified correlation charts showing the viscosity behavior of air, water, gas and crude oil and gas-saturated crude oil under oil field temperatures and pressures, which have been known to be as high as 300°F. and 8000 lb. per sq. in. gauge under subsurface conditions.

The viscosity of a liquid or gas is important because it is a measure of its fluidity, or its ability to flow through pipe lines or oil sands. Viscosity of air has become important because it is being used in secondary^{1,2} recovery projects. The viscosity of natural gas and water at reservoir conditions is useful because they are almost universally associated and produced with crude oil. The viscosity of gas-saturated crude oil at reservoir pressures and temperatures is of particular value in making estimates of oil reserves³ and rate of oil recovery from flush pools when production decline data are limited.

INSTRUMENTS USED TO MEASURE VISCOSITY

There are many types of viscosimeters,⁴ and the instruments most commonly used to measure the atmospheric viscosity of liquids at moderate temperatures and their practical working ranges have been described^{5,6} in detail. Fig. 1 and Fig. 2 are viscosity conversion charts which have

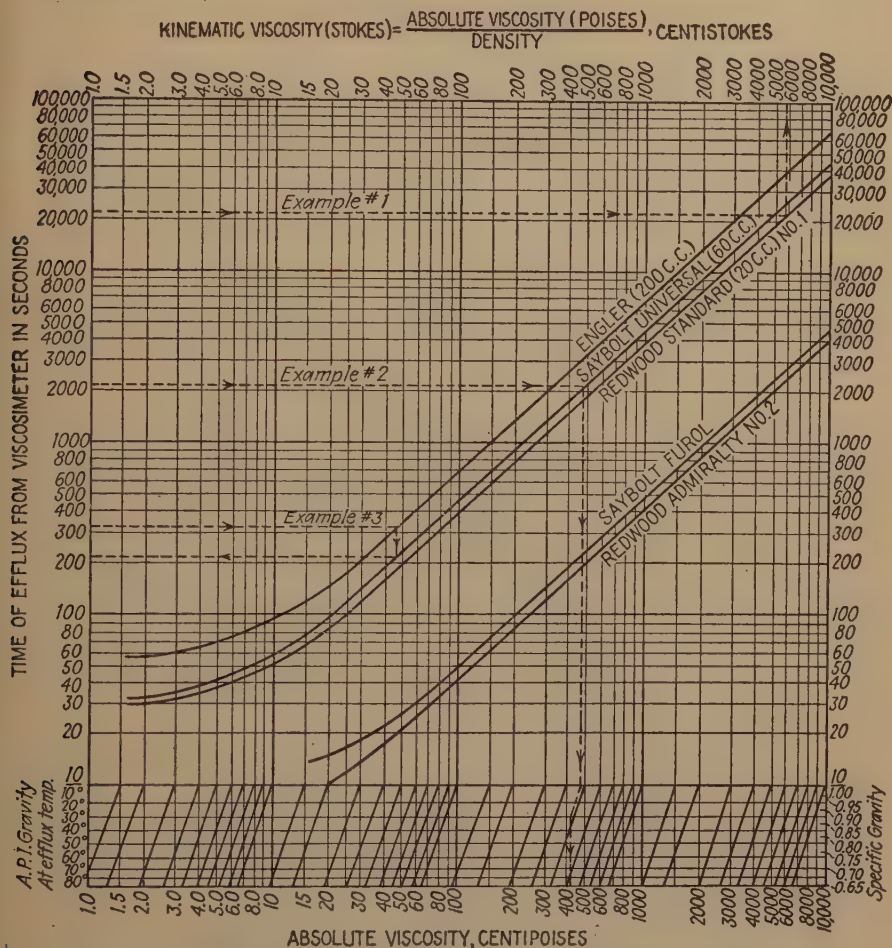
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* Consulting Petroleum Engineer, Los Angeles, California.

¹ References are at the end of the paper.

proved helpful in converting viscosimeter seconds to kinematic, or absolute viscosity; and converting Saybolt seconds at crude oil

the Hoeppler "rolling ball" viscosimeter and the modified Rankine capillary viscosimeter.⁸



EXAMPLE #1: Time of efflux from Redwood instrument = 22500 seconds; Corresponding KINEMATIC VISCOSITY (see dotted line #1) = 5800 centistokes

EXAMPLE #2: Saybolt time = 2200 seconds, A.P.I. gravity at efflux temp. = 30°: ABSOLUTE VISCOSITY (see dotted line #2) = 420 Cp

EXAMPLE #3: Engler efflux time = 330 seconds; Corresponding Saybolt time (see dotted line #3) = 220 seconds

Note: To convert 150,000 Engler sec. to absolute viscosity read from the chart the value corresponding to 15,000 sec. and multiply by 10. By this method any desired conversion may be made

o Based on TP #210 U.S. Bureau of Stds.

* Based on TP #112 U.S. Bureau of Stds.

FIG. 1.—VISCOSITY CONVERSION CHART.
Compliments of Shell Oil Company Inc.

gravity to absolute viscosity in centipoises.

The viscosity of natural gas and gas-saturated crude oil at elevated temperatures and pressures is measured with

VISCOSITY OF AIR AND WATER

The viscosity of air^{9,10} at elevated temperatures and pressures is summarized on Table 1. Results of cross-plotting

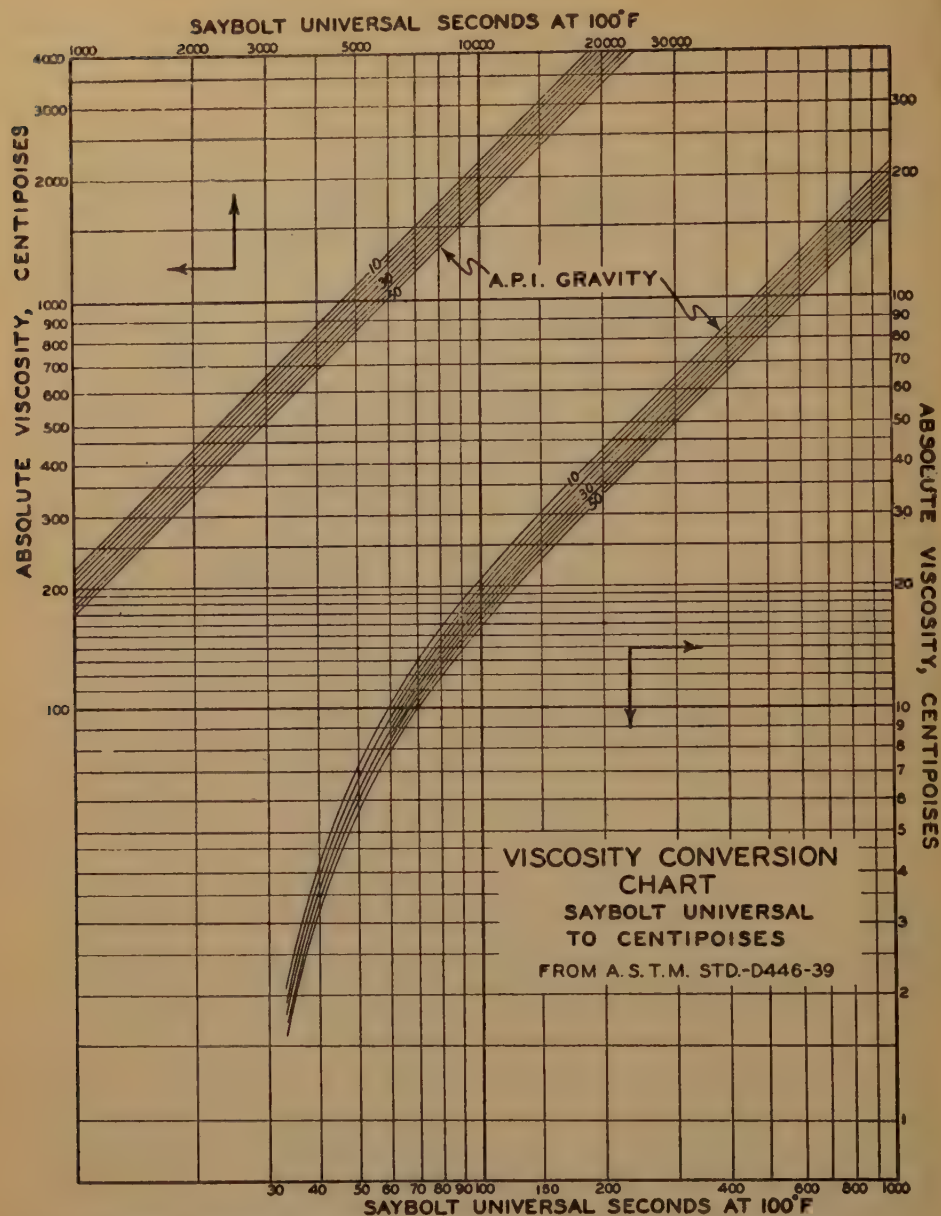


FIG. 2.—Viscosity conversion chart, Saybolt Universal to Centipoises.
 From A.S.T.M. Std. D446-39.
 Compliments of E. V. Watts, General Petroleum Corporation.

reported values show that the viscosity of air is roughly that of natural gas at comparable pressures and temperatures, and increases with increasing pressure and temperature.

TABLE 1.—*Viscosity of Air at High Pressures and Temperatures*

Temperature, Deg. F.	Absolute Viscosity, Centipoises		
	At ^a 14.7 Lb. per Sq. In. Abs.	At ^b 1420 Lb. per Sq. In. Abs.	At ^b 4260 Lb. per Sq. In. Abs.
32	0.01709	0.02020	0.02810
50	0.01759		
60.8		0.02065	0.02780
68	0.01808		
86	0.01856		
104	0.01904		
122	0.01951	0.02200	0.02770
140	0.01997		
158	0.02043		
176	0.02088		
194	0.02132		
212	0.02175	0.02400	0.02880
302	0.02385		
392	0.02582		

Pressures are converted from reported data to pounds per square inch absolute by:

Kg per sq. cm. $\times 14.2 =$ lb. per sq. in.

Temperatures are converted from reported data to degrees F. by:

$^{\circ}\text{F.} = 1.8^{\circ}\text{C.} + 32$

^a From reference 9.

^b From reference 10.

The viscosity of water has been investigated by Bridgman,¹¹ the results¹² of which are shown on Table 2. A plot of the data on Fig. 4 shows that the viscosity of water decreases from 1.4 to 0.4 cp. as a result of increasing the temperature from 50° to 200°F. The change in water viscosity, as a result of increasing pressure from 14.2 to 7100 lb. per sq. in. abs. for all practical purposes, is negligible. The viscosity of water at its vapor pressure⁹ (pressure of saturated vapor at indicated temperature) is shown on Table 3. Values are plotted on Fig. 4 and show only a small deviation in viscosity from constant pressure values of 14.2 and 7100 lb. per sq. in. abs., respectively.

Dodson and Standing¹³ and others¹⁴ have found that small amounts of gas can be dissolved in salt water at oil field

temperatures and pressures. While no data have been published showing the effect of dissolved salts and solution gas on water viscosity, these variables may have a much greater effect on the viscosity of water than pressure.

TABLE 2.—*Viscosity^a of Water at High Pressures and Temperatures*

Pressure, Lb. per Sq. In. Abs.	Absolute Viscosity, Centipoises			
	32°F.	50.5°F.	86°F.	166.6°F.
14.2	1.792	1.40	0.871	0.396
7,100	1.680	1.35	0.895	0.411
14,200	1.65	1.33	0.921	0.428
21,300	1.67	1.33	0.950	0.443
28,400	1.71	1.35	0.986	0.461 [*]

Pressure was converted from reported values in kilograms per square centimeter to pounds per square inch absolute by multiplying by 14.2.

Reported values were converted to absolute viscosity by multiplying "relative viscosity" by 1.792, the viscosity of water at 32°F. and 14.2 lb. per sq. in. absolute.

^{*} See reference 11.

TABLE 3.—*Viscosity of Water at Various Temperatures^a and at Vapor Pressure*

Temperature, Deg. F.	Viscosity, Cp.	Vapor Pressure, ^b Lb. per Sq. In. Abs.
32	1.79	0.0886
50	1.31	0.180
68	1.00	0.339
86	0.801	0.616
104	0.656	1.07
122	0.549	1.79
140	0.469	2.89
158	0.406	4.52
176	0.357	6.87
194	0.316	10.18
212	0.284	14.7
230	0.256	20.8
284	0.196	52.4
321	0.174	89.6

^a See reference 9.

^b Pressure is that of the saturated vapor at the indicated temperature.

VISCOSITY OF NATURAL GAS

The viscosity of a mixture of gases such as natural gas cannot be determined from the viscosity of the component gases on which ample data have been published, as the mixture may have a greater viscosity than any of the component gases.¹⁵ The viscosity of natural gas has been recorded by a number of investigators,^{8,16} particularly

Bicher and Katz,¹⁷ who have investigated the viscosity of methane, propane and four methane-propane mixtures at pressures ranging from 400 to 5000 lb. per sq. in. abs.

taken directly from Katz and Bicher's work by converting to centipoises (cp.) and gas gravity at four temperatures (60° 100°, 200°, and 300°F.).

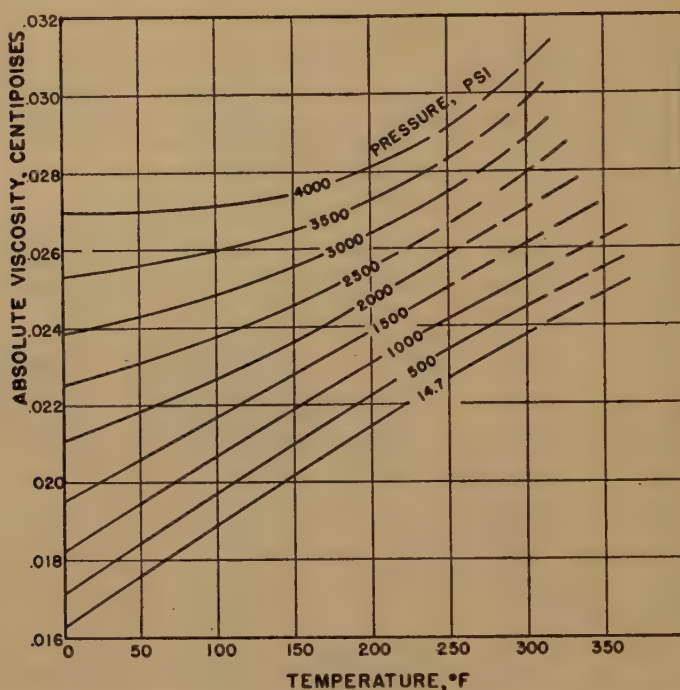


FIG. 3.—VISCOSITY OF AIR AT OIL FIELD TEMPERATURES AND PRESSURES.

and temperatures ranging from 77° to 437°F. The authors correlated their laboratory investigations with work done by previous investigators¹⁸ who had recorded the atmospheric viscosity of natural gas at temperatures ranging from minus 40° to 896°F. The authors presented results of the correlation as three figures, plotting the relationship of gas viscosity (micro-poise) as a function of molecular weight at six temperatures (0°, 60°, 100°, 200°, 300°, and 400°F.) and pressures measured to 5000 lb. per sq. in. abs. and extrapolated to 10,000 lb. per sq. in. abs. One of the most convenient and commonly used terms in calculations of natural gas is the specific gas gravity relative to air, which has a molecular weight of 28.97. Figs. 5 and 6 are

VISCOSITY OF GAS-FREE CRUDE OIL AT 100°F.

Because of the varying compositions of different crude oils, predictions of crude oil viscosity from simple correlations cannot be made with extreme accuracy. Oil gravity and temperature are the most critical variables that affect crude oil viscosity—the higher the temperature and gravity, the lower the crude oil viscosity. Johnston and Sherborne^{19,20} gave a relation between crude oil viscosity at 100°F. and oil gravity. The correlation includes, in part, results from Trostel's²¹ work, which presented an approximate relationship between A.P.I. gravity and viscosity of more than 200 samples of California crude

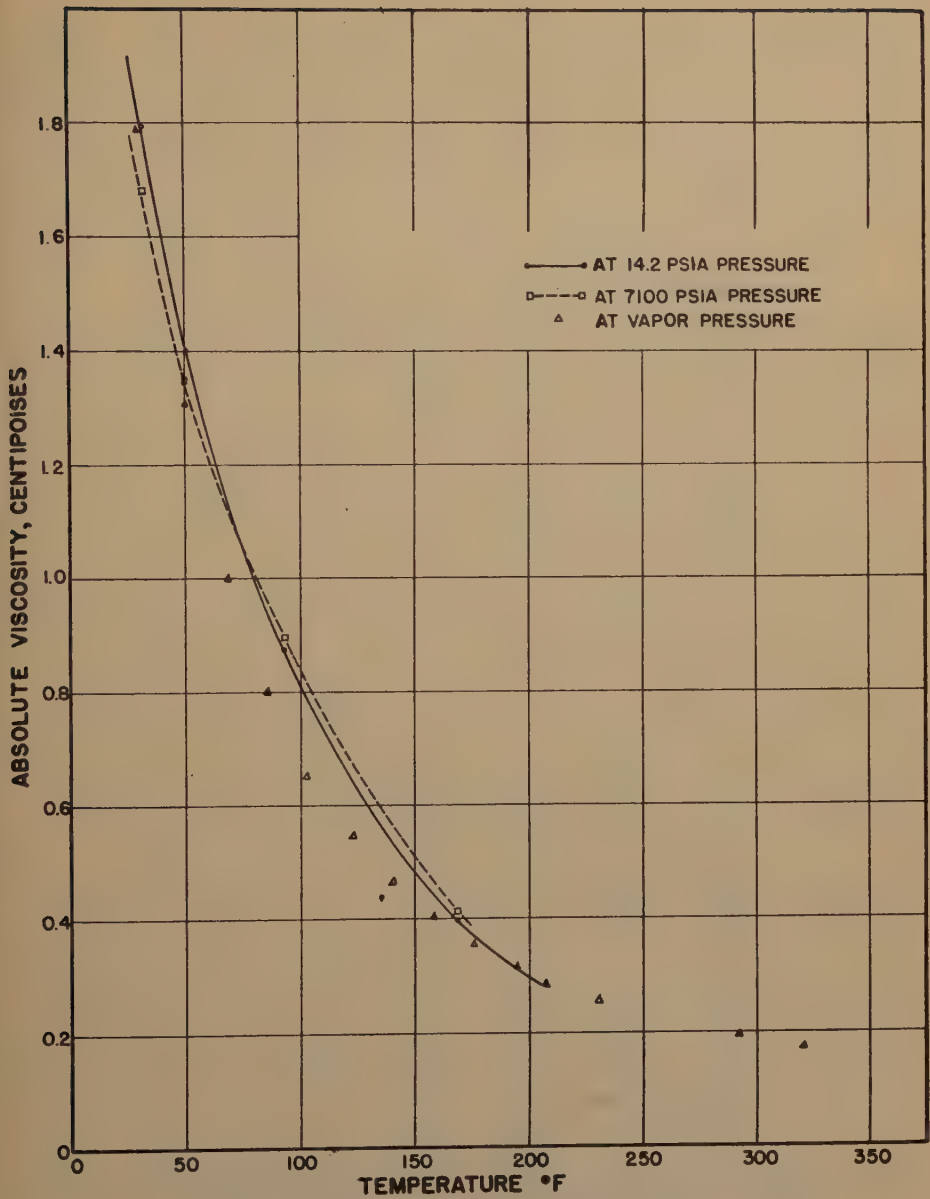


FIG. 4.—VISCOSITY OF WATER AT OIL FIELD TEMPERATURES AND PRESSURES.

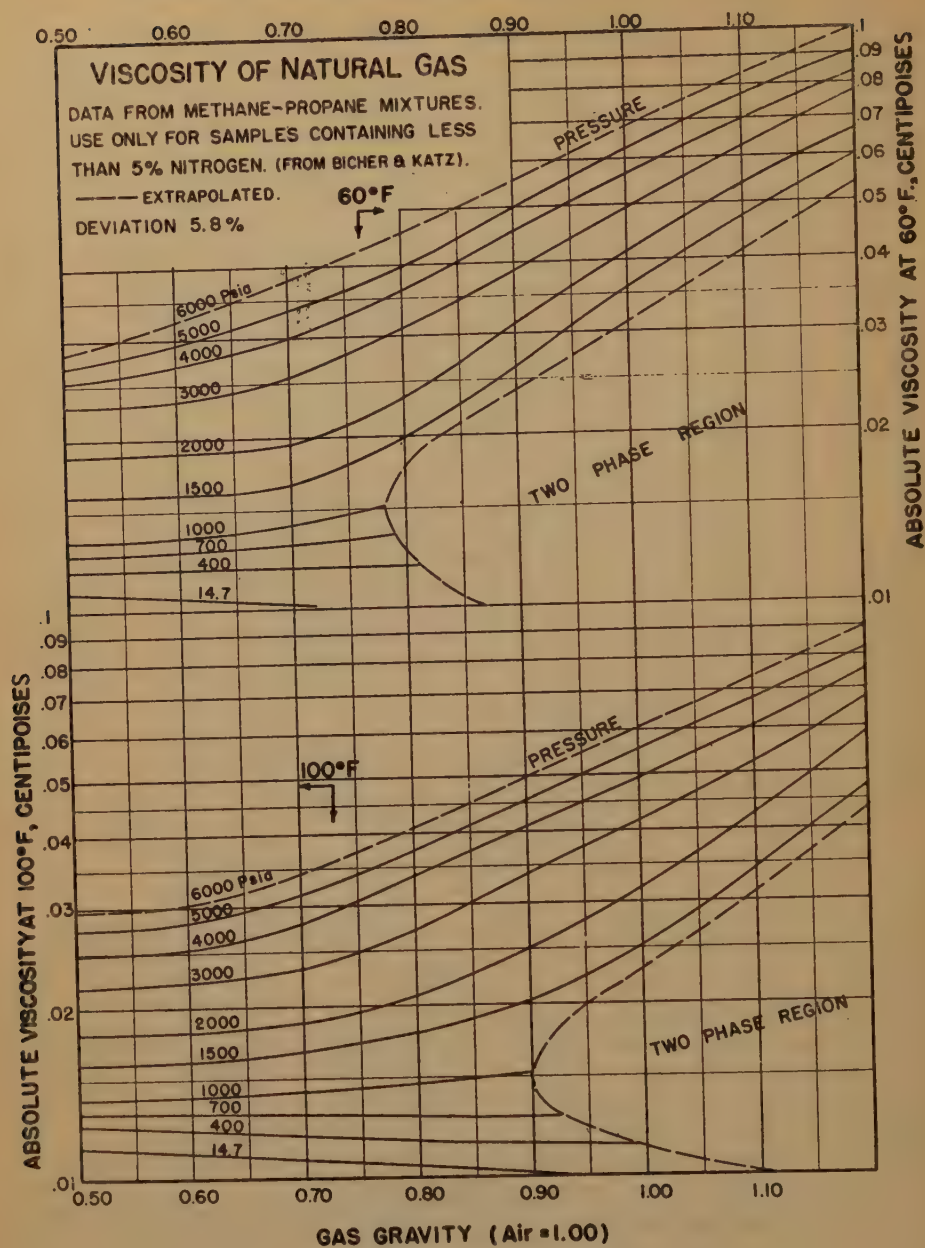


FIG. 5.—VISCOSITY OF NATURAL GAS.

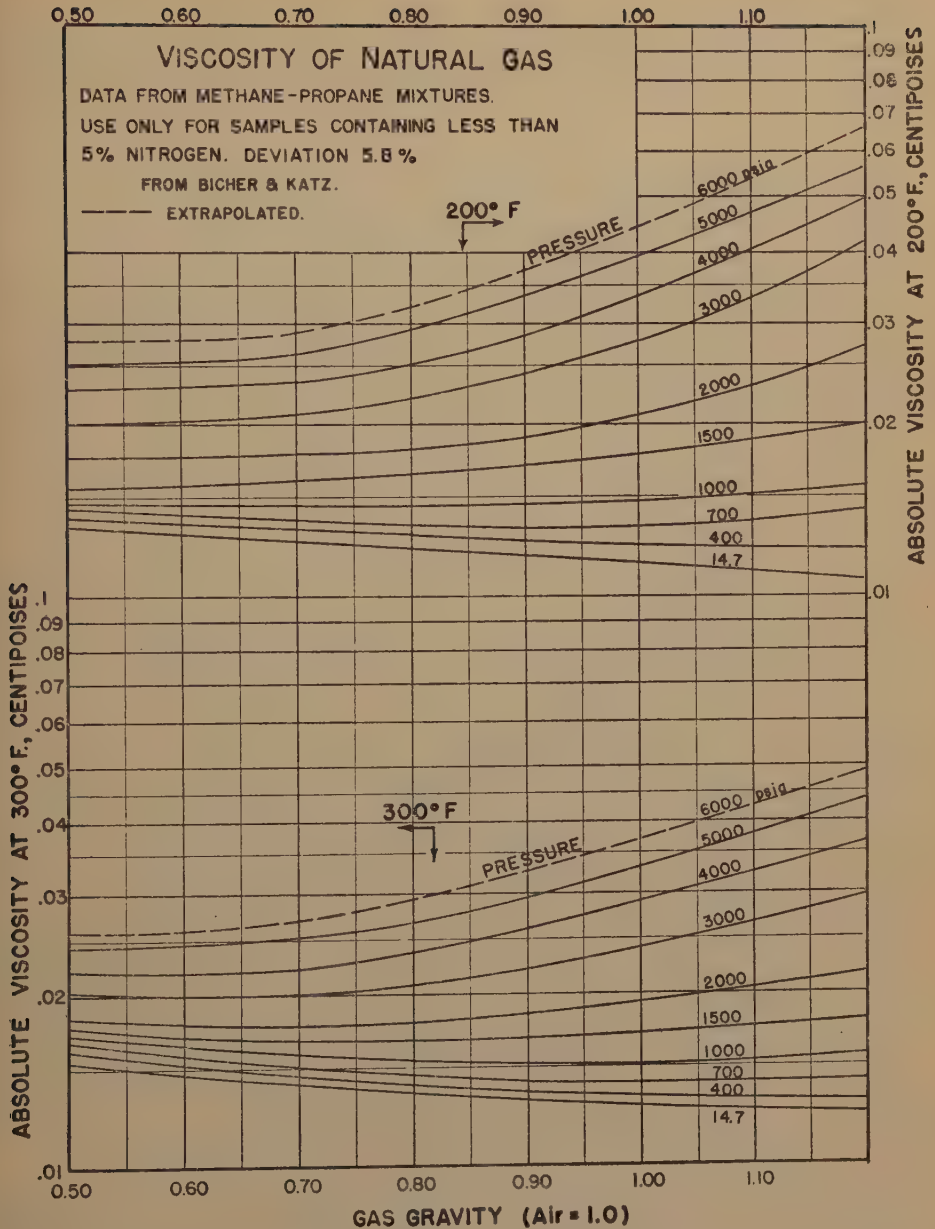


FIG. 6.—VISCOSITY OF NATURAL GAS.

oils at 100°F. This work has been found representative of California where lower gravity crude oils are more commonly produced.

from 492 oil fields, of which 358 are in the United States. Trostel's and Johnston's temperature-oil gravity relationship for California crude oils is shown on Fig. 7

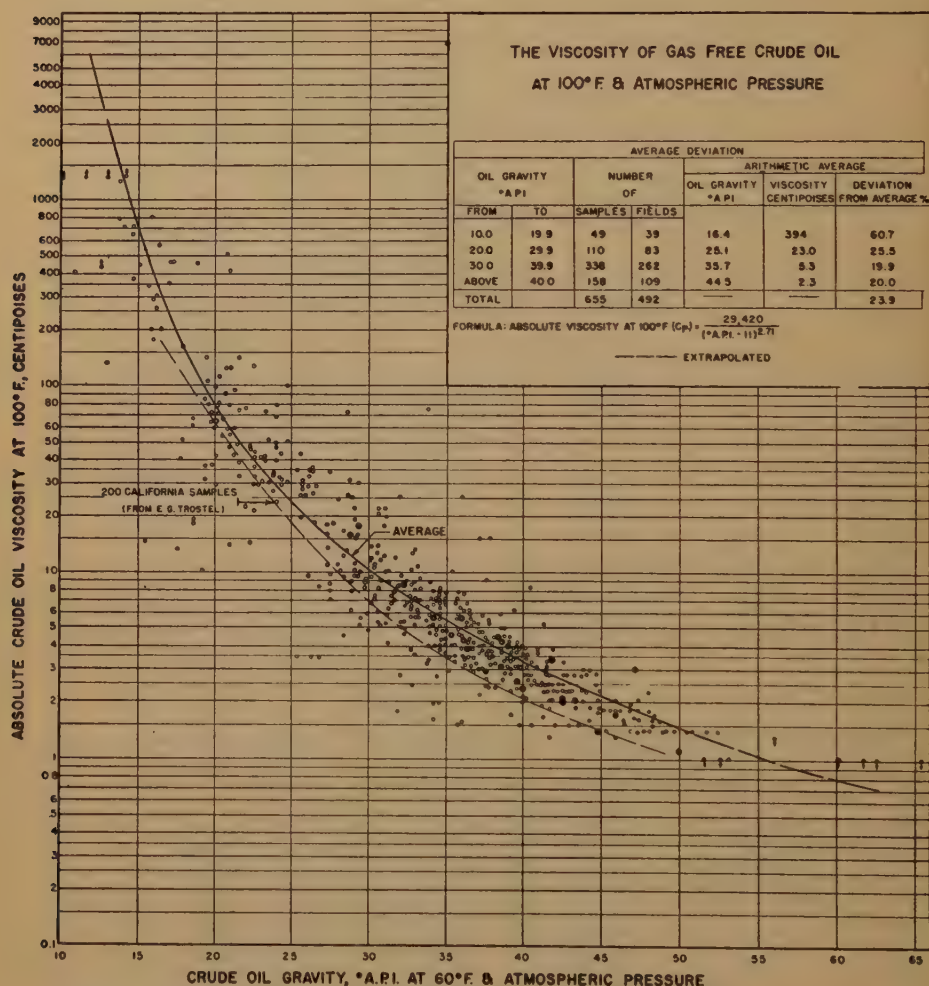


Fig. 7.—Viscosity of gas-free crude oil at 100°F. and atmospheric pressure.

Because of the wealth of published viscosity measurements at a temperature of 100°F., a plot was made of 655 gas-free samples of crude oil viscosity measurements at 100°F., which were obtained from many sources.²²⁻²⁶ The samples represent the viscosity of crude oil taken

for comparison with the 655 plotted values. While data on the individual samples are too numerous to publish, the table on Fig. 7 shows a recapitulation of the samples used in constructing the chart. The mean deviation of all viscosity measurements from the average curve was 29.0 per cent.

VISCOSITY OF GAS-FREE CRUDE OIL AT OIL FIELD TEMPERATURES

Since the reservoir temperature of most oil fields is above 100°F., the effect of

was from 10.1° to 52.5° A.P.I., and the viscosity range was from 0.865 to 1550 cp. Deviation of samples from the average curves are tabulated on the figure for

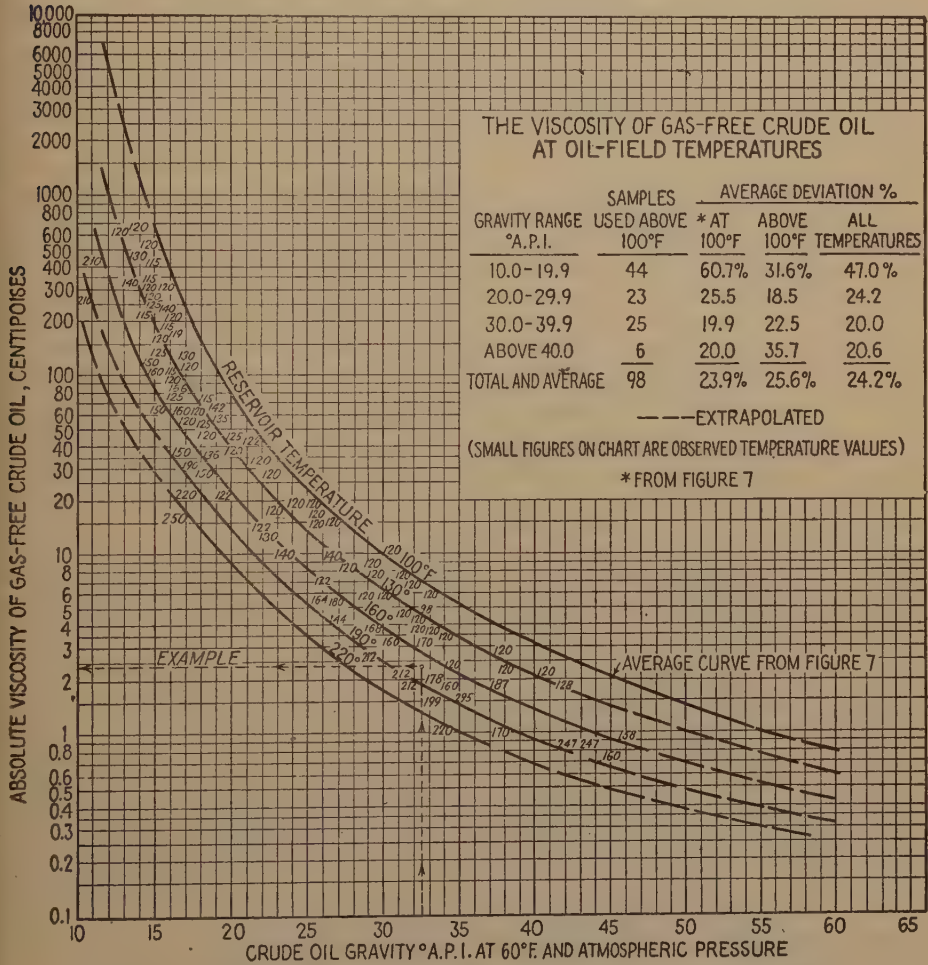


FIG. 8.—VISCOSITY OF GAS-FREE CRUDE OIL AT OIL FIELD TEMPERATURES.

higher temperatures on viscosity of gas-free crude oil is useful for viscosity predictions. The data from Fig. 7 and the viscosity data for 98 samples of gas-free crude oil measured at temperatures above 100°F. was used as a basis for constructing Fig. 8. The range in oil gravity for these samples

gravity and temperature ranges. The average deviation of all samples above 100°F. was 25.6 per cent, while California values showed an average deviation of 23.1 per cent. The average deviation of all samples from all temperature curves (100° to 220°F., incl.) was 24.2 per cent.

VISCOSITY OF GAS-SATURATED CRUDE*
OIL AT OIL FIELD TEMPERATURES
AND PRESSURES

Beecher and Parkhurst³⁷ observed that the viscosity of crude oil is reduced when saturated with gas under pressure. They pointed out the importance of maintaining the gas in the crude oil to increase ultimate recovery. Other early investigators, including Finch and Hobro³⁸ determined that heavy oils experience a greater percentage reduction in viscosity as a result of gas saturation under pressure, the amount of decrease depending principally on pressure, reservoir temperature and the characteristics of the oil and gas.

Hocott and Buckley³⁶ presented the results of viscosity determinations of typical Mid-Continent crude oil, which clearly illustrated the wide variation in the viscosity behavior of individual crude oils, a characteristic that is also typical of California crude oils. Viscosity of gas-saturated crude oils depends on many variables; namely, temperature, oil and gas gravity, pressure, gas in solution, bubble-point pressure and base (chemical composition) of crude. The viscosity may not be predicted accurately from these variables because of the difficulty in determining the effects of chemical composition of various crudes. Although accurate predictions may not be expected, any empirical relation that would permit the estimate of the viscosity of crude oil within a degree of accuracy sufficient for oil-field estimates would be helpful.

Johnston and Sherborne²⁰ have presented an empirical method for estimating viscosity of crude oil at reservoir temperature and pressure by applying a "viscosity reduction factor" to the gas-free crude oil viscosity at 100°F. The viscosity reduction is based on Dominguez³⁴ and Santa Maria²⁹

crudes, having oil gravities of 33.9° and 17.0° A.P.I., respectively. Since Santa Maria viscosity data were used for crude oil gravities below 20° A.P.I., and Dominguez viscosity data for crude oil gravities above 20° A.P.I., considerable error is likely to be encountered at gravities removed from either 17.0° or 33.9° A.P.I.

Fig. 9 shows the results of plotting 351 bubble-point viscosity observations from crude oil samples, representing 29 oil fields, as a function of gas in solution at reservoir pressure. Results show that:

1. Most crude oils follow a general pattern of decline in oil viscosity as a function of dissolved gas relative to the viscosity of a gas-free crude oil at reservoir temperature.

2. The greater reduction in viscosity occurs at low values of gas saturation in low-gravity crude oils, and this reduction decreases as the gravity of the crude and the pressure increase.

3. The amount of gas dissolved (solubility) in crude oil for a particular oil gravity has a more important bearing on gas-saturated crude oil viscosity than has pressure.

TABLE 4.—Average Deviation of Random Samples

Observation Taken	Number of Random Samples	Average Deviation, per cent	
		This Correlation (Fig. 9)	Johnston and Sherborne ²⁰
Roughly half way between atmospheric and pool bubble-point pressure.....	25	11.3	43.0
Near pool bubble-point pressure.....	27	15.1	34.4
Total and average	52	13.4	38.5

A comparison of the average deviation of random samples, using this correlation and Johnston and Sherborne's²⁰ is shown in Table 4.

* This is "bubble point" crude oil at any pressure; not to be confused with the "bubble point" pressure for a particular oil pool.

GAS SOLUBILITY IN CRUDE OIL

The viscosity of a gas-saturated crude oil can be predicted from Fig. 9 as a function of gas in solution. A knowledge of the

reported the effect of pressure and temperature on the solubility of gas in three crude oils having gravities of 35.8°, 48.2° and 63.4°A.P.I. Katz⁴⁰ presented a method of

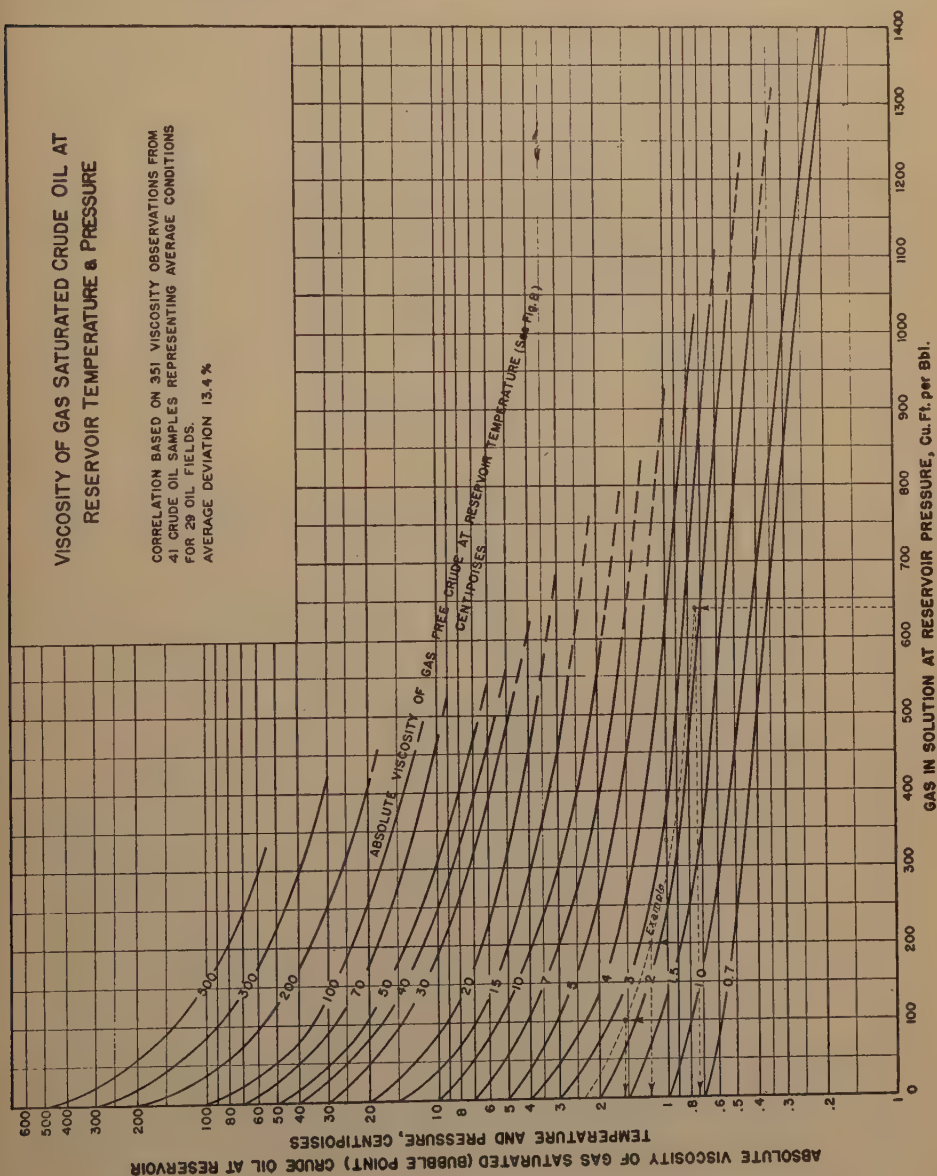


FIG. 9.—VISCOSITY OF GAS-SATURATED CRUDE OIL AT RESERVOIR TEMPERATURE AND PRESSURE.

reservoir pressure at this gas-saturated crude oil viscosity is essential for proper oil field valuation. Gosline and Dodson³⁹

predicting the solubility of gas in crude oil for various saturation pressures within 25 per cent error. His work was based on

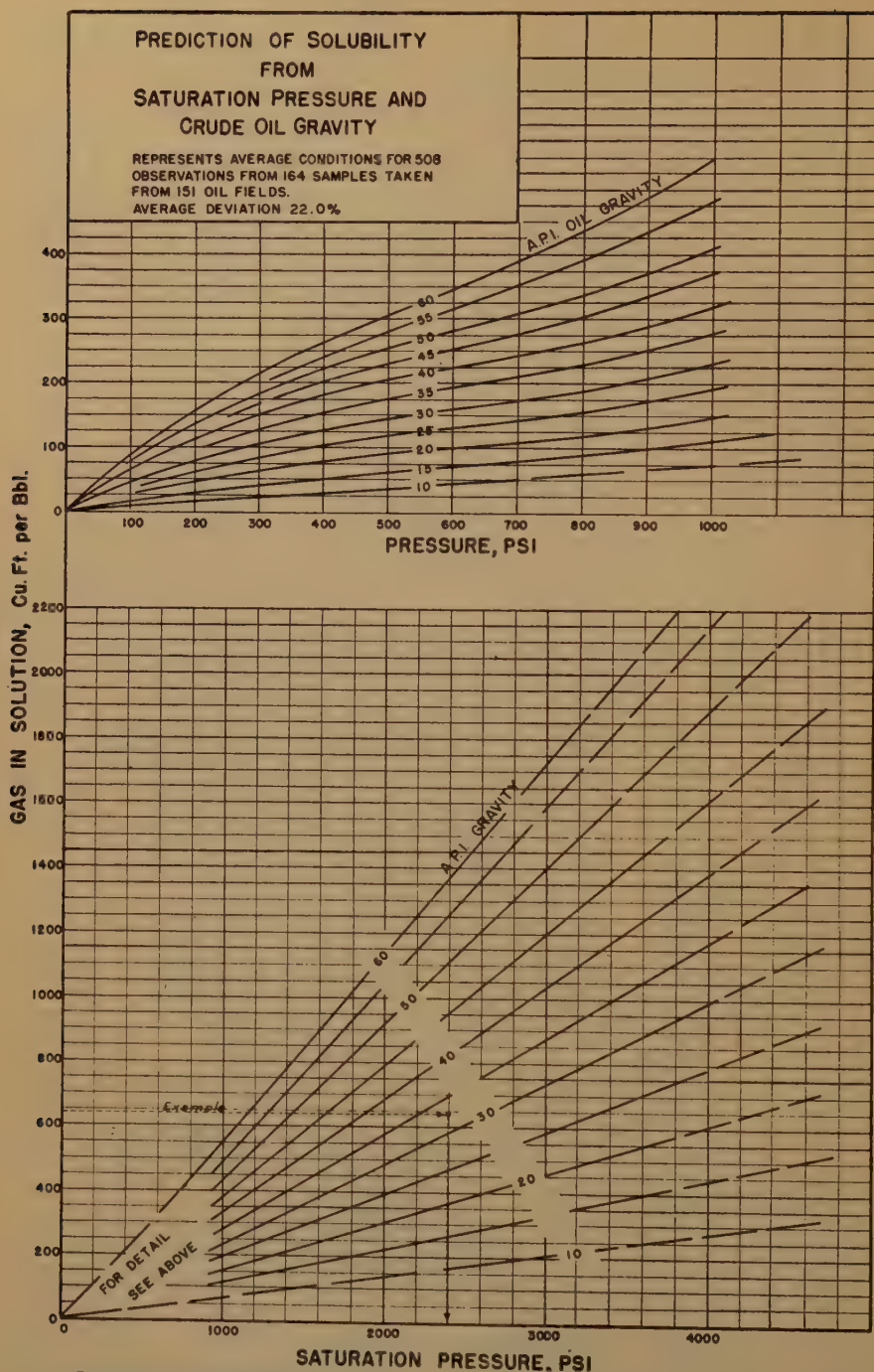


FIG. 10.—PREDICTION OF SOLUBILITY FROM SATURATION PRESSURE AND GRAVITY OF CRUDE OIL.

TABLE 5.—Range of Gas-saturated Crude Oil Viscosity Determinations Used for Correlation

Key	Number of Samples	Number of Viscosity Observations	Gravity Range, Deg. A.P.I.	Temperature Range, Deg. F.	Viscosity Range, Cp.	Maximum Gas-oil Ratio, Cu. Ft. per Bbl.
1	1	20	34.6	235	1.00- 0.33	868
2	1	10	27.0	144	4.26- 1.78	333
3	3	38	18.1-19.9	135-142	19. - 66.0	135
4	1	7	33.5	178	0.40- 2.00	978
5	1	13	32.6	178	0.58- 3.18	675
6	1	9	32.5	158	0.92- 3.52	453
7	2	23	42.0-43.0	247	0.14- 1.00	1827
8	3	16	15.8-30.5	156-168	1.00-89.5	380
9	1	5	16.0	119	127. -315.	12
10	4	36	29.4-33.1	199-212	0.59- 2.52	663
11	1	7	37.0	187	0.60- 1.90	710
12	1	6	38.0	170	0.60- 1.00	520
13	5	33	29.0	163	1.50- 3.90	440
14	1	6	45.0	160	0.38- 0.74	600
15	1	6	26.0	157	2.35- 7.0	340
16	6	80	17.0	100-250	3.36- 3.50	457
17	4	28	33.9	100-220	0.56- 3.34	972
18	1	2	29.7	100	5.05- 8.21	191
19	1	2	26.1	164	5.26- 2.00	385
20	1	2	41.5	128	1.85- 0.95	293
21	1	2	45.7	158	0.95- 0.48	800
Total...	41*	351				

* From 29 oil pools; 20 from California.

TABLE 6.—Determinations Used for Prediction of Undersaturated Crude Oil Viscosity above Bubble-point Pressure

Sample No.	At Bubble Point*			Above Bubble Point†		Viscosity Increase Above B.P., Cp. per 1000, Lb. per Sq. In. Gauge	Average Deviation from Fig. 11, Per Cent
	Gas in Solution, Cu. Ft. per Bbl.	Pressure, Lb. per Sq. In. Gauge	Absolute Viscosity, Cp.	Pressure, Lb. per Sq. In. Gauge	Absolute Viscosity, Actual, Cp.		
1	452	2,800	0.78	3,200	0.82	0.098	2.5
2	165	1,400	10.1	1,600	10.4	1.500	0.8
3	393	2,900	6.60	4,850	8.00	0.720	3.1
4	600	2,541	0.48	4,000	0.59	0.076	11.3
5	333	1,644	1.78	2,250	1.88	0.165	1.6
6	143	1,187	19.2	2,000	20.	0.984	8.0
7	129	1,500	24.7	2,000	26.7	3.920	0.4
8	60	600	38.0	1,500	44.8	6.556	4.1
9	69	800	20.1	1,500	24.5	6.286	8.4
10	675	3,130	0.57	4,200	0.61	0.037	0.0
11	453	3,000	0.93	3,500	0.96	0.060	0.0
12	1,827	4,120	0.142	5,500	0.16	0.013	0.0
13	967	4,070	0.206	5,000	0.24	0.031	9.1
14	12	125	127.	3,860	315.	50.333	0.0
15	605	3,200	0.59	4,400	0.66	0.058	3.1
16	614	3,500	0.65	4,200	0.68	0.043	0.0
17	591	3,200	0.74	4,000	0.77	0.375	1.3
18	191	660	5.05	3,000	6.30	0.534	3.3
19	385	2,700	2.00	3,000	2.08	0.267	2.0
20	293	735	0.96	3,000	1.10	0.062	0.0
21	800	2,150	0.49	3,000	0.52	0.035	0.0
22	710	3,900	0.60	4,500	0.65	0.083	4.8
23	520	2,160	0.60	3,000	0.64	0.048	1.6
24	440	2,600	1.5	3,000	1.55	0.125	1.3
25	600	2,077	0.38	3,000	0.40	0.022	2.4
26	340	2,325	2.35	3,000	2.45	0.148	0.0
Average.							2.7

* For a particular oil pool.

† In undersaturated region.

117 samples from fields chiefly situated in the Mid-Continent and eastern areas of the United States. Solubility observations from samples taken from California fields (where there are more low-gravity crude oils produced) confirm Katz's work for crude oil gravities between 20° and 45°A.P.I. , with an average deviation of 20.0 per cent. However, for oil gravities below 20°A.P.I. , the average deviation was 48.9 per cent.

Fig. 10 shows the results of correlating Katz's work with 391 solubility relations observed from 47 samples taken from 34 California oil pools. This made possible better correlation at lower oil gravities. Prediction of gas solubility in crude oil from crude oil gravity and saturation pressure can be made with an average deviation of 22.0 per cent, which includes a deviation of only 20.4 per cent for crude oil gravities below 20°A.P.I.

VISCOSITY OF UNDERSATURATED CRUDE OIL ABOVE "THE BUBBLE-POINT PRESSURE"

Pressure becomes of primary importance in estimating crude oil viscosity in the undersaturated region. After the bubble point has been reached, and the pressure is increased, the viscosity of the undersaturated crude oil also increases, which means that special consideration should be given to correlation of the undersaturated viscosity behavior of crude oils.

No methods of predicting the viscosity of undersaturated crude oil above the bubble-point pressure have been published. In deep oil fields we frequently find that the reservoir crude oil was originally undersaturated with gas or had an original pressure above the "bubble point." If the original pressure is in excess of the estimated, or measured, bubble-point pres-

sure, it may be desirable to predict the increase in viscosity of the crude oil as it becomes more undersaturated at these higher pressures.

Table 6 shows the results of correlating 52 viscosity observations taken from 26 crude oil samples, representing 20 individual oil pools, 11 of which are in California. Half of the observations include viscosity data for the undersaturated crude oil above the bubble point, and the other half are viscosity observations at the bubble point. The behavior of these samples indicates that a greater viscosity increase occurs as the absolute bubble-point viscosity increases. The viscosity of all of the samples was noted to increase in proportion to the increase in pressure above the bubble point.

Fig. 11 shows the relation between the rate of change of the undersaturated crude oil viscosity per unit pressure increase above the bubble-point pressure, and the bubble-point crude oil viscosity. A visual average relation was drawn through the calculated values on Fig. 11 and the results were converted to a correlation of absolute values in Fig. 12. The prediction of the viscosity of the 26 undersaturated crude oil samples above the bubble-point pressure from Fig. 12 showed an average deviation of 2.7 per cent, which is within the range of experimental error.

PREDICTION OF CRUDE OIL VISCOSITY

For illustration, measured viscosity data from a sample taken from the Grubb Two Pool, San Miguelito field, California, are compared with estimates made from the correlation charts. Field data given are:

1. Crude oil gravity, 32.6°A.P.I.
2. Original solution gas-oil ratio, 638 cu. ft. per barrel.
3. Maximum reservoir pressure at minus 6950 ft. subsea is 4200 lb. per sq. in. gauge.
4. Reservoir temperature, 178°F.

From Fig. 8, the viscosity of the gas-free crude oil at 178°F. is 2.30 cp. (average

* The reservoir pressure of an oil pool at which the crude oil is completely saturated with gas. The crude oil becomes undersaturated as reservoir pressures exceed the pool bubble point.

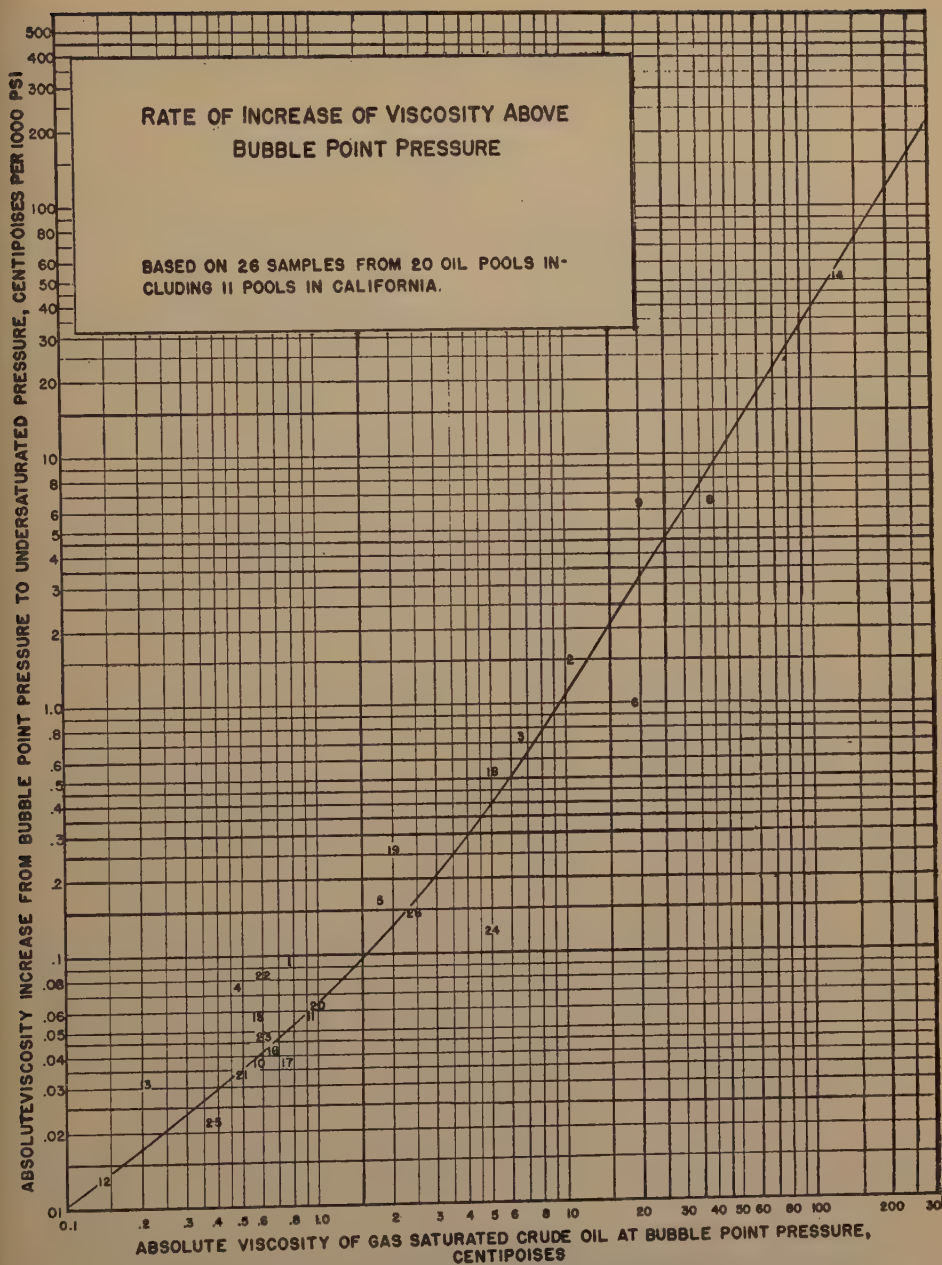


FIG. 11.—RATE OF INCREASE OF VISCOSITY ABOVE BUBBLE-POINT PRESSURE.

Shows observed values located by sample number from Table 6. Average deviation 2.7 per cent.

deviation 20.8 per cent). Following the example shown on Fig. 9 for a crude-oil viscosity of 2.30 cp., a number of estimates of saturated crude-oil viscosities (deviation

per sq. in. gauge from 3000 to 4500 (covering the range of maximum reservoir pressure) from Fig. 12 (deviation 2.7 per cent) after subtracting the bubble-point pressure

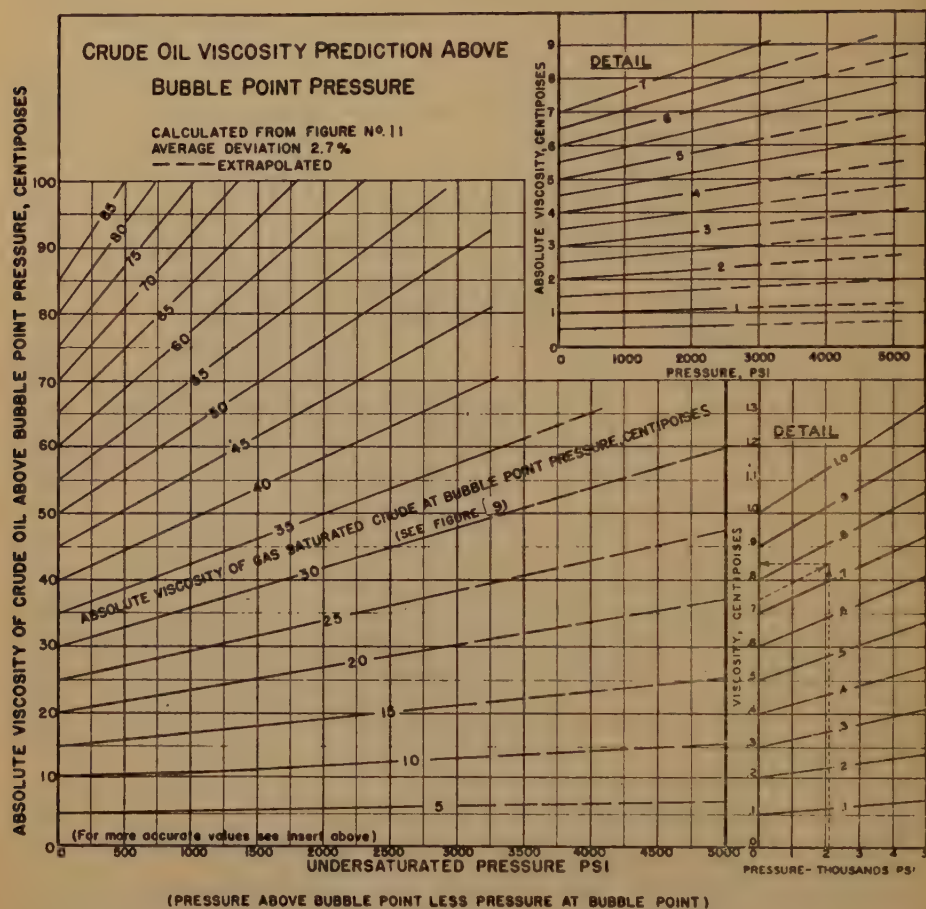


FIG. 12.—PREDICTION OF CRUDE OIL VISCOSITY ABOVE BUBBLE-POINT PRESSURE.

14.2 per cent) are obtained for gas-oil ratios less than 638 cu. ft. per bbl. Corresponding reservoir pressures are obtained for these viscosity values from Fig. 10 with an average deviation of 22.0 per cent. The pressure necessary to hold 638 cu. ft. of gas per barrel for this crude oil is estimated from Fig. 10 to be 2400 lb. per sq. in. gauge. The undersaturated crude oil viscosity is obtained at intervals of 500 lb.

from the reservoir pressure values. A comparison of the measured values with the predicted values are shown on Table 7 and illustrated in Fig. 13. The table shows that the average deviation of the predicted values from the measured values is 23.5 per cent.

Fig. 14 shows the measured viscosity data at reservoir conditions of temperature and pressure for crude oils from five oil

pools, selected at random to cover a representative spread of absolute viscosity over a wide oil-gravity range. The figure compares measured data with viscosity

cent), while others show marked deviation (39.4 per cent) from average trends.

ADDITIONAL RESEARCH

A review of the factual data in literature indicates that the following research may prove to be helpful in increasing the accuracy of predicting viscosity behavior:

1. What is the effect of dissolved salts and solution gas on the viscosity of salt water under high pressures and temperatures?

2. What is the effect of nitrogen contamination on the viscosity of natural gas at high pressures and temperatures?

3. What is the viscosity of air-gas mixtures at oil field pressures and temperatures?

This paper shows clearly that there is considerable error involved in predicting the viscosity behavior of crude oil without taking into account fundamental variables such as gas gravity and composition of crude oil. Methods of predicting the viscosity behavior of bubble-point crude oil at high temperatures and pressures may be improved by correlation of these additional variables.

SUMMARY AND CONCLUSIONS

Conversion charts that are often necessary for converting viscosity units to centipoises are included in the report. The viscosity of air and water at oil field

TABLE 7.—Comparison of Measured Crude Oil Viscosity Data with Predicted Values for San Miguelito-Grubb II Pool, California

Reservoir Pressure, Lb. per Sq. In. Gauge	Estimated Gas in Solution (Fig. 10), Cu. Ft. per Bbl.	Absolute Viscosity, Cp.			
		From	From Correlation	Measured Value	Deviation, Per Cent
0	0	Figs. 8 and 9	2.30	3.18	27.7
235	100		1.55	2.32	33.1
725	200		1.18	1.52	22.3
1170	300		0.98	1.15	14.8
1530	400		0.89	0.96	7.3
1900	500		0.82	0.83	1.2
2400	638		0.74	0.70	5.7
3000	638		0.77	0.60	35.0
3130	638			0.57	
3500	638		0.795	0.58	37.0
4000	638	Fig. 12	0.83	0.60	38.5
4500	638		0.85	0.62	37.0
Average..					23.5

predictions taken from the correlation charts and using the tabulated field data for the individual pools. The average deviation of the predicted values from the measured values was 19.8 per cent. The illustration indicates that the viscosity behavior of some crude oils can be predicted within a fair degree of accuracy (8.5 per

TABLE 8.—Distribution of Samples Used for Viscosity and Solubility Correlations

Item	Number of Viscosity and Solubility Observations	Number of Samples of Crude Oil	Oil Pools Represented			
			Foreign	U. S. A. Except California	California Only	Total
Gas-free crude oil:						
At 100°F.....	655	655	134	345	13	492
Any other temperature.....	131	108	37	21	27	85
Gas-saturated crude oil:						
Viscosity and solubility.....	351	41	0	9	20	29
Solubility only.....	117 ^a	117 ^a	0	117 ^a	0	117 ^a
Undersaturated crude oil.....	78	32	0	9	15	24
Total.....	1,322	953	171	501	75	747

^a From reference 40.

temperatures and pressures is taken from published sources and converted to common units for convenient interpretation. A correlation used by Bicher and Katz to

viscosity of crude oil under various conditions were constructed from the use of 1215 viscosity observations from 836 samples of crude oil taken from 630 oil

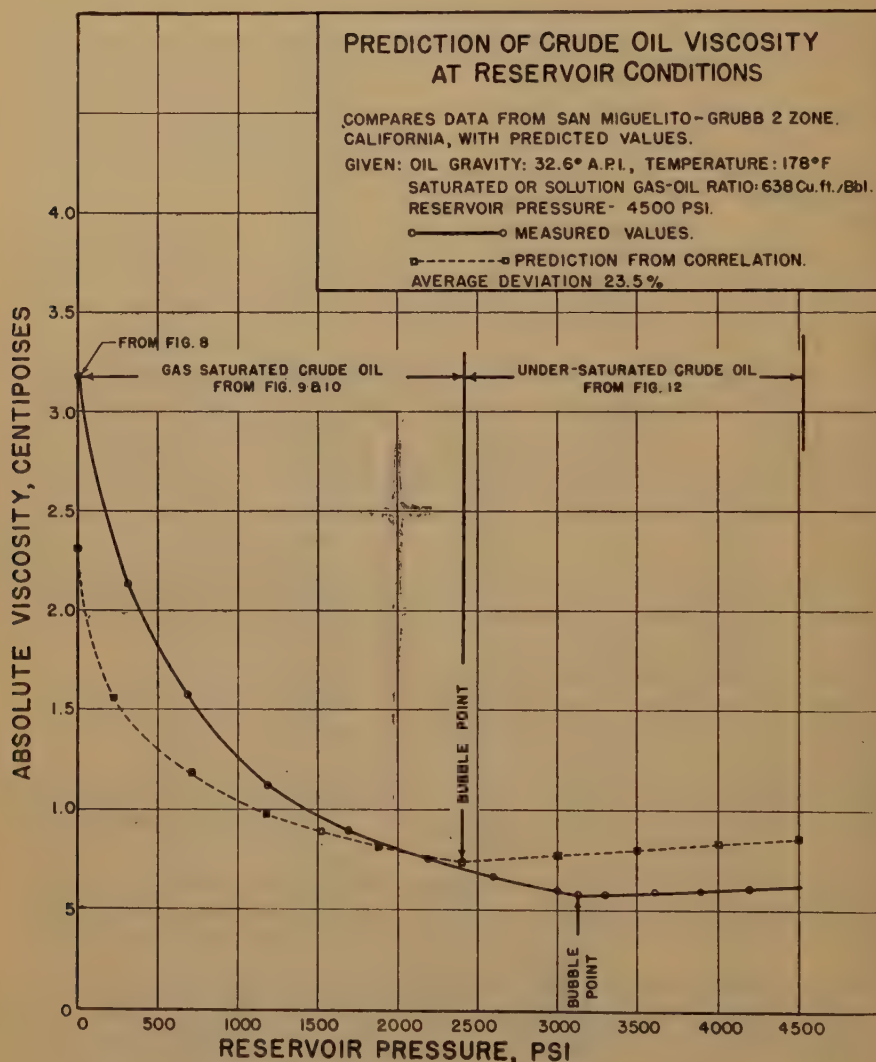


FIG. 13.—PREDICTION OF CRUDE OIL VISCOSITY AT RESERVOIR CONDITIONS.

predict the viscosity of natural gas is presented, using common units, from which the viscosity of gas can be predicted with an average deviation of 5.8 per cent.

Correlation charts for predicting the

fields. Of the oil fields represented, 459 are in the United States, including 75 fields in California. The distribution of samples used for correlations is shown in Table 8.

COMPARISON OF CRUDE OIL VISCOSITY PREDICTIONS WITH MEASURED DATA FOR 5 OIL FIELDS

KEY	DATA GIVEN			MAXIMUM PRESSURE PSI	AVERAGE DEVIATION %
	API	TEMPERATURE °F	SOLUTION GAS/OIL RATIO		
(A)	27.0	144	333 Cu.ft./Bbl	2825	39.4
(B)	18.1	138	143	1187	8.5
(C)	33.5	178	978	3800	13.3
(D)	23.8	156	221	1222	11.0
(E)	17.0	220	431	3250	23.8
AVERAGE					19.8

—○— MEASURED VALUES
- - -○- - - PREDICTED VALUES

ABSOLUTE VISCOSITY, CENTIPOISES

BUBBLE POINT

BUBBLE POINT

RESERVOIR PRESSURE, PSI

FIG. 14.—COMPARISON OF PREDICTIONS OF CRUDE OIL VISCOSITY WITH MEASURED DATA FOR FIVE OIL FIELDS.

The viscosity of gas-free crude oil at reservoir temperature can be predicted with an average deviation of 24.2 per cent from correlation of oil gravity and temperature. A method is presented for predicting the viscosity of gas-saturated crude oil at reservoir temperature and pressure with an average deviation of 13.4 per cent, using only the viscosity of the gas-free crude oil at reservoir temperature and the quantity of gas in solution. The prediction of gas solubility in crude oil at various pressures, temperatures and oil gravities can be made from a correlation of 351 viscosity observations with an average deviation of 22.0 per cent. The absolute viscosity of the under-saturated crude oil at high pressures above the bubble point can be predicted with an average deviation of 2.7 per cent, using the viscosity of bubble-point crude oil predicted from a previous correlation and reservoir pressure. In conclusion, the crude oil viscosity at reservoir temperature and pressure may be predicted with a 19.8 per cent deviation, having knowledge of only the oil gravity, original gas-oil ratio, and reservoir temperature and pressure.

ACKNOWLEDGMENT

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Core Analysis Based on Vacuum Distillation

By CARROL M. BEESON* AND NORRIS JOHNSTON,* MEMBERS A.I.M.E.

(Los Angeles Meeting, October 1945)

ABSTRACT

THE gravimetric-vacuum distillation method was developed to permit rapid and accurate determinations of the oil-water ratios of small samples or sands containing little oil. In addition, the samples usually are so well cleaned and so little altered by the distillation at reduced pressure that rapid estimations of other physical properties may be made with the evacuated cores.

Requiring only elementary glass-blowing technique, the distilling tubes and traps used in determining oil-water ratios were easily fashioned from the usual glassware. A sketch and description are given of the necessary apparatus, including the cylindrical electrical heaters. The procedure, requiring about 40 min., consists in raising the temperature and maintaining it between 675° and 725°F. for at least 10 min. while the pressure is held between 1 and 2 mm. Hg. The fluids condensed in the trap (cooled by a mixture of kerosine and solid carbon dioxide) are separated in a centrifuge and the volume of water is recorded. Determination of changes in weight with an analytical balance of all parts of the apparatus permits computation of weight of oil distilled and total weight of oil recovered.

INTRODUCTION

In determining the oil-water ratios of core samples, distillation at atmospheric pressure¹⁻⁵ has proved to be sufficiently reliable for samples containing moderate quantities of oil. Since small samples and sands with little oil are encountered, how-

ever, it appeared advisable to develop a method that would be applicable under these circumstances.

The gravimetric-extraction procedure^{1,6-9} undoubtedly is very reliable and could be used in all tests, but the time consumed in the determination would often delay field operations. This would be especially true when dealing with tight sands or viscous oils, both of which retard the extraction process.

Accordingly, the gravimetric-vacuum distillation method was developed in order to combine the good features of both of the older methods; that is, accuracy and speed. By reducing the pressure, it was found possible to perform the distillation at a temperature that permits the use of glass apparatus, all parts of which can be weighed on an analytical balance. Thus, the fluids may be removed quickly from the core, the water is readily trapped and measured, and the loss in weight of the core is easily determined. In addition, the total weight of material condensed in the distilling tube and in the trap provides a method of determining the oil-water ratio that is practically independent of the one involving the loss in weight of the sample.

The use of vacuum not only permits as much accuracy as does the gravimetric-extraction process, but it actually allows an increase in speed over the atmospheric-distillation method, because of the time required to cool the metal pots from about 1200°F. between runs. More important yet, the innovation makes possible the almost immediate reporting of permeability, and saturation, which is impossible

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* Chemical Engineer and Physicist, respectively, General Petroleum Corporation of California, Los Angeles, California.

¹ References are on page 120.

with either of the older methods. This unique advantage depends upon the fact that the sample usually is so well cleaned and so little altered by the distillation that properties may be measured with the evacuated core.

APPARATUS*

A sketch of a single unit is shown in Fig. 1. The sample container was fashioned from a 20-ml. beaker by removing the rim, attaching a wire loop handle, and sealing glass beads on the outside of the bottom and sides. For a distilling tube, a 7-cm. length of 9-mm. tubing was attached to the bottom of a 38 by 200-mm. Pyrex test tube. The tube is closed at the top with a Neoprene stopper containing a 760°F. thermometer placed so that the bulb reaches to within 2 or 3 cm. of the top of the sample. The 9-mm. tubing connects with the inner tube of the trap directly below, through a second Neoprene stopper.

The outer part of the trap consists of a portion (length 8 cm., capacity 4 ml.) of a 10-ml. Pyrex delivery pipette closed at the bottom and attached to a 9-cm. length of 25-mm. tubing. The jacket, with sidearm near the top leading to vacuum, is attached by a ring-neck seal to a 9-cm. length of 19-mm. tubing, which extends to within 2 cm. of the narrow, graduated tube.

The electrical heating system is composed of six cylindrical electrical heaters and a transformer wired so that 0, 80, or 120 volts may be imposed upon any one of the heaters, producing 0, 128, or 288 watts. Each heater, 4 in. long, consists of 19.5 ft.

of No. 26 Nichrome wire of specific resistance 2.57 ohms per ft. wound over a mica-covered hard-drawn brass tube with brass collars welded to each end. This tube has

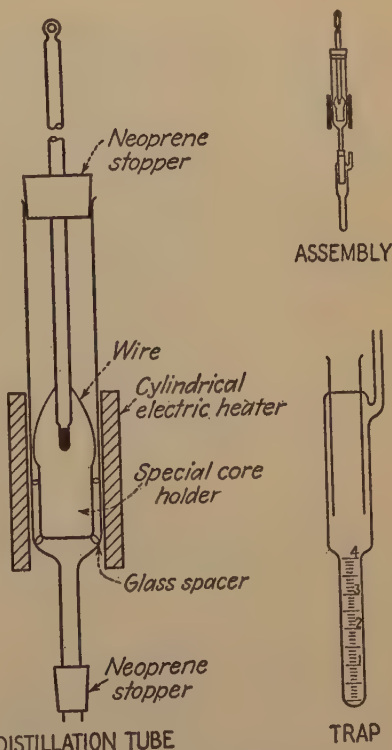


FIG. 1.—APPARATUS FOR VACUUM DISTILLATION OF CORES.

an inside diameter of $1\frac{5}{8}$ in. and a wall thickness of $\frac{1}{16}$ in. The winding, covered with porcelain cement, is attached to a strip of Transite, which also contains hooks for mounting the heater. The outer sheath is made of stainless steel.

PROCEDURE

Before a run is started, each sample container, distilling tube with stopper and thermometer, and trap is weighed to the nearest milligram.

A sample, about 2 by 2 by 4 cm., is placed in one of the special containers, container and sample are quickly weighed and

* Subsequent to obtaining the data of this report, several changes were made in the apparatus. The Neoprene stopper that connected the distilling tube and trap was replaced by a glass spherical joint (18/9). This permitted the 9-mm. tubing to be shortened to about 3 cm. and allowed the inner and outer tubes of the trap to be reduced to 11 mm. and 17 mm., respectively. In addition, a glass spherical joint (12/5) was attached to the sidearm of the trap.

introduced into a distilling tube, which is then stoppered. The necessary number of samples thus having been prepared, parts of the apparatus are assembled, and the

the wire handle attached to the container and the loss in weight is determined, as well as the gain in weight of the tube with stopper and thermometer.

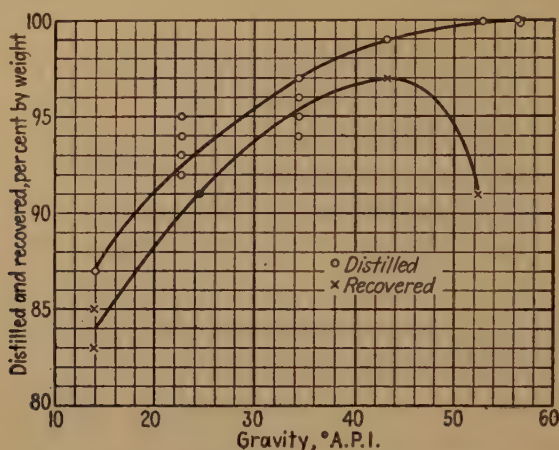


FIG. 2.—OIL DISTILLED AND RECOVERED.

traps are surrounded with a fluid mixture of kerosine and solid carbon dioxide. With the trap outlets connected to the atmosphere, the cylindrical electrical heaters are turned on at full capacity.

When the temperature has risen to about 600°F., the pressure is reduced slowly enough so that liquid does not evaporate at a violent rate from any of the tubes. As the temperature in each tube approaches 700°F., the low and high heat switches are manipulated manually so as to maintain a temperature of $700 \pm 25^\circ\text{F.}$ for at least 10 min. while the pressure is 1.5 ± 0.5 mm. Hg.

At the end of the distillation (about 40 min. total), dry air is admitted, the tubes are withdrawn from the heaters, and the traps are removed from the coolant and lightly capped. When the contents of the traps have liquefied, they are separated in a centrifuge, the volumes of oil and water are recorded, and the traps are weighed. After a container and evacuated core have attained room temperature, they are removed from the distilling tube with aid of

RESULTS OF THE CALIBRATION TESTS*

When water was distilled from glass wool, the weight of recovered water agreed to within ± 0.01 gram of the known weight. During the distillation of both water and oil from glass wool, the estimation of water collected in the trap agreed, on the average, to within ± 0.02 ml. (extreme -0.05 ml.) with the volume originally added.

For crude oils with respective gravities of 14°, 24°, 34°, 43°, and 53°A.P.I., 87, 93, 96, 99, and 100 per cent of the weight of oil was distilled, while 82, 91, 95, 97, and 91 per cent of the weight of the oil was recovered in both the trap and distilling tube. The data have been plotted in Fig. 2.

The distillation of Cleveland Quarry sandstone, artificially impregnated with oil and water, yielded results in agreement with those obtained by the distillations involving glass wool. With natural consolidated cores, the difference between the

* The details and analysis of the calibration runs have been grouped in the Appendix.

core oil, as computed from change in weight of core and from weight of oil recovered, averaged ± 0.04 gram and varied from -0.06 to $+0.06$ gram.

Air permeabilities and porosities (and consequently saturations) may be estimated from measurements with evacuated cores. In fact, the divergence of results obtained by various methods of measuring porosity was much greater than that due to the introduction and distillation of oil. For values of air permeability between 3.8 and 317 md., the ratio of the value obtained after evacuation to the original varied from 0.95 to 1.61 and averaged 1.22. In addition, most of the air permeabilities and porosities measured after extraction or after vacuum distillation of adjacent samples of natural consolidated cores agreed very well.

Water permeabilities should be measured with samples cleaned by extraction, since enough water of crystallization apparently was distilled from the sands and clays that hydrational effects were eliminated to a considerable extent.

The gravity of the crude may be estimated from that of the oil collected in the trap, as shown in Fig. 3. The data indicated that the gravity of the crude could be estimated to within about 1°A.P.I., providing the amount collected does not differ from the expected value by more than 10 per cent.

Since 1943, when core analysis based on vacuum distillation was developed, the method has proved to be a powerful tool for the core laboratory. It is always used for determining the oil-water ratio of small (wire-line) cores or of any samples containing so little oil that the desired degree of accuracy cannot be attained by atmospheric distillation; because for samples of like size, an oil-water ratio determined by the older method is subject to about 10 times as large an error as is one determined by vacuum distillation. The apparatus is used also whenever a complete

analysis is needed in a hurry. The method was not developed to displace atmospheric distillation for determining the oil-water ratio of appropriate samples, but rather to

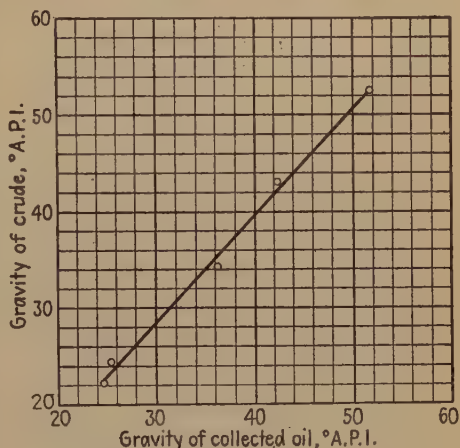


FIG. 3.—CHANGE IN GRAVITY OF OIL DURING VACUUM DISTILLATION.

complement the older one. When time permits, adjacent cores are extracted* for measurement of saturation, porosity, and permeability. It should be readily apparent that the proper combination of extraction, atmospheric distillation, and vacuum distillation allows cores to be analyzed with almost any degree of accuracy and speed.

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* In determining saturation by extraction, the weights of core oil and water are computed from the loss in weight of the sample during extraction and the oil-water ratio of an adjacent sample as obtained by atmospheric or vacuum distillation. This seems preferable to assuming the porosities of adjacent samples to be equal, because the latter assumption may introduce a percentage error in the saturation equivalent to the percentage error in the assumed porosity. On the other hand, assuming the oil-water ratio of adjacent samples to be equal introduces an error in saturation that is greatly reduced by the relatively small differences between the densities of crude oils and of water.

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APPENDIX

Calibration Tests for Determination of Oil-water Ratio

Although it is possible that the use of sand may not safely be omitted from all calibration runs, experiments in which glass wool is substituted for sand increase greatly the accuracy of calibration. As shown in a later section, the kind or quantity of the porous medium has little effect upon the results obtained by vacuum distillation. Furthermore, the ever present possibility that materials other than oil or water will be distilled from sand, as well as loss of water of crystallization, tends to obscure the calibration. The former factor is especially operative in the gravi-

metric-vacuum method, and so many tests were made with glass wool replacing the sand.

As was to be expected, no difficulty was experienced in recovering the water by the procedure given above. In the absence of oil, 4.020 and 4.060 grams of water, respectively, were recovered from 4.027 and 4.047 grams contained in glass wool. The apparent loss of 0.007 gram and gain of 0.013 gram may be considered as inaccuracies that are of little consequence.*

Oil and Water Distilled from Glass Wool (or Sand)

The most immediate use of core-analysis data is in distinguishing oil sands from water sands. Especially when coupled with measurements of permeability, this knowledge aids greatly in the proper development of the drilling and completion program. By comparing production data with those obtained from core analysis, the oil-water ratio has been found to be a fairly good criterion for differentiating oil and water sands. In addition, the critical ratio (above which oil is produced and below which water is produced) depends to a considerable extent upon the gravity of the oil. For example, at oil gravities of 15°, 25°, 35°, and 45°A.P.I., the critical oil-water ratios for many California fields appear to be approximately 0.21, 0.14, 0.09, and 0.06, respectively.

Many of the results were obtained, then, at ratios near those values. Additional calibration tests at about three times the critical ratio were also found to be helpful.

The following data were obtained by the regular procedure with the two indicated exceptions in which the pressure was maintained at 4 ± 0.5 mm. Hg (instead of the usual 1.5 ± 0.5 mm.) for 10 min. while the temperature was $700^\circ \pm 25^\circ\text{F}$.

* However, this source of error has since been eliminated by replacing the Neoprene stopper with a glass spherical joint (18/9).

TABLE I.—*Vacuum Distillation of Oil and Water from Glass Wool or Sand*

Oil.....	Crude Oil A, 13.8°A.P.I., Critical O/W 0.21				Crude Oil B, 22.3°A.P.I., Critical O/W 0.16				
Trap No.....	2	6	6 ^a	5 ^a	6	5	6	5	2
Solid.....	S ₂	G	G	G	G	G	G	G	S ₂
O ₀ , gram.....	0.42	0.40	1.26	1.24	0.32	0.31	0.90	0.90	1.00 ^b
O, ml.....	0.43	0.42	1.29	1.28	0.35	0.34	0.98	0.98	1.10 ^b
W, ml.....	2.19	2.09	2.15	2.13	2.19	2.06	2.14	2.22	1.70 ^b
O/W.....	0.20	0.20	0.60	0.59	0.16	0.16	0.46	0.44	0.65
O', ml.....	0.20	0.18	0.82	0.75	0.16	0.26	0.69	0.74	0.80
W', ml.....	2.23	2.07	2.17	2.14	2.19	2.07	2.12	2.23	1.70
W'', ml.....	2.19	2.07	2.17	2.14	2.19	2.07	2.12	2.23	1.70 ^b
O'/O, per cent.....	46	43	64	59	46	76	70	76	73
W'/W, per cent.....	100	99	101	100	100	100	99	100	100 ^b
O _d , gram.....	0.37	0.35	1.03	1.03	0.30	0.29	0.83	0.84	0.90
O _d /O ₀ , per cent.....	8	87	82	83	94	95	92	93	90
O' _d , gram.....	0.43	0.40	1.18	1.18	0.32	0.31	0.80	0.90	0.97
O' _d - O ₀ , gram.....	+0.01	±0.00	-0.08	-0.06	±0.00	±0.00	-0.01	±0.00	-0.03
O'', ml.....	0.44	0.41	1.22	1.22	0.35	0.34	0.97	0.98	1.05
O''/W''.....	0.20	0.20	0.56	0.57	0.16	0.16	0.46	0.44	0.62
O''/W'' - O/W.....	±0.00	±0.00	-0.04	-0.02	±0.00	±0.00	±0.00	±0.00	-0.03
O'' - O, ml.....	+0.01	-0.01	-0.07	-0.06	±0.00	±0.00	-0.01	±0.00	-0.05
W'' - W, ml.....	±0.00	-0.02	+0.02	+0.01	±0.00	+0.01	-0.02	+0.01	0.90
O _r , gram.....	0.32	0.34	1.00	0.97	0.28	0.29	0.78	0.81	0.90
O _r ', gram.....	0.32	0.33	1.01	0.97	0.28	0.29	0.78	0.81	0.90
O _r '/O ₀ , per cent.....	76	83	(80) ^c	(78)	87	93	87	90	(90)
O _r ', gram.....	0.39	0.41	1.22	1.18	0.31	0.33	0.91	0.91	1.01
O _r ' - O ₀ , gram.....	-0.03	+0.01	-0.04	-0.06	-0.01	+0.02	+0.01	+0.01	+0.01
O _r '', ml.....	0.40	0.42	1.26	1.22	0.34	0.36	0.98	0.99	1.10
O _r ''/W''.....	0.18	0.20	0.58	0.57	0.16	0.17	0.46	0.44	0.65
O _r ''/W'' - O/W.....	-0.02	±0.00	-0.02	-0.02	±0.00	+0.01	±0.00	±0.00	±0.00

Oil.....	Crude Oil D, 34.2°A.P.I. Critical O/W 0.09				Crude Oil E, 56.2°A.P.I. Critical O/W 0.04				
Trap No.....	6	2	6	5	6	5	6	6	5
Solid.....	G	G	G	G	G	G	G	G	G
O ₀ , gram.....	0.17	0.16	0.47	0.47	0.10	0.10	0.10	0.30	0.27
O, ml.....	0.20	0.19	0.55	0.55	0.13	0.14	0.14	0.40	0.35
W, ml.....	2.01	2.03	2.18	2.17	3.16	3.13	3.16	3.39	3.34
O/W.....	0.10	0.09	0.25	0.25	0.04	0.04	0.04	0.12	0.10
O', ml.....	0.11	0.12	0.33	0.30	0.04	0.11	0.09	0.26	0.22
W', ml.....	2.02	2.03	2.17	2.18	3.11	3.14	3.11	3.37	3.36
W'', ml.....	2.02	2.03	2.17	2.18	3.11	3.14	3.11	3.37	3.36
O'/O, per cent.....	55	63	60	66	31	78	64	65	63
W'/W, per cent.....	100	100	100	100	98	100	98	99	101
O _d , gram.....	0.16	0.15	0.45	0.40	0.10	0.10	0.10	0.30	0.27
O _d /O ₀ , per cent.....	95	94	96	97	100	100	100	100	100
O' _d , gram.....	0.17	0.16	0.47	0.48	0.10	0.10	0.10	0.30	0.27
O' _d - O ₀ , gram.....	±0.00	±0.00	±0.00	±0.01	±0.00	±0.00	±0.00	±0.00	±0.00
O'', ml.....	0.20	0.19	0.55	0.56	0.13	0.14	0.14	0.40	0.35
O''/W''.....	0.10	0.09	0.25	0.26	0.04	0.04	0.05	0.12	0.10
O''/W'' - O/W.....	±0.00	±0.00	±0.00	+0.01	±0.00	±0.00	±0.00	±0.00	±0.00
O'' - O, ml.....	±0.00	±0.00	±0.00	+0.01	±0.00	±0.00	±0.00	±0.00	±0.00
W'' - W, ml.....	+0.01	±0.00	-0.01	+0.01	-0.05	+0.01	-0.05	-0.02	+0.02
O _r , gram.....	0.13	0.14	0.44	0.41	0.08	0.10	0.10	0.25	0.18
O _r ', gram.....	0.13	0.14	0.44	0.41	0.03	0.10	0.05	0.23	0.20
O _r '/O ₀ , per cent.....	(77)	(87)	94	87	(30)	(100)	(50)	77	74
O _r ', gram.....	0.14	0.15	0.46	0.43	0.09	0.11	0.11	0.28	0.20
O _r ' - O ₀ , gram.....	-0.03	-0.01	-0.01	-0.04	-0.01	-0.01	+0.01	-0.02	-0.07
O _r '', ml.....	0.16	0.18	0.54	0.51	0.12	0.15	0.15	0.37	0.27
O _r ''/W''.....	0.08	0.09	0.25	0.23	0.04	0.05	0.05	0.11	0.08
O _r ''/W'' - O/W.....	-0.02	±0.00	±0.00	-0.02	±0.00	+0.01	+0.01	-0.01	-0.02

^a These two runs were made at a minimum pressure of 4 ± 0.5 mm. Hg (instead of the usual 1.5 ± 0.5 mm.)

^b The loss of water of crystallization from this sand was not measured, and total recovery of water was assumed in computing the indicated values.

^c The figures in parentheses were omitted in determining averages of total weight recovery of oil.

The letters O and W refer to volume of oil and water, and O with a subscript applies to weight of oil. The respective subscripts o , d , and r signify original, distilled, and total recovered weight. Primes or double primes attached to W and O indicate, respectively, collected or corrected volumes. However, O'' depends upon weight of oil distilled and not volume collected. The analogous corrected volume of oil, depending on total weight of recovered oil, has been designated by O''' . The symbols O'_d and O'_r represent corrected weights of oil, the former having been corrected for percentage distilled and the latter for percentage recovered. The weight of recovered oil, as obtained by assuming total recovery of water, has been denoted by O''_r .

The symbols S_u , S_c , and G imply respectively that the porous medium to which oil or water had been added was unconsolidated sand (air permeability about 1000 md.), consolidated sand (air permeability about 50 md.), or glass wool.

As noted in the procedure, all weighings were made to the nearest milligram. Although the last figure has not been included in the table, it has been used in computing the recorded percentages that do not depend on volumetric measurements.

In the test that involved unconsolidated sand, the water of crystallization collected from a similar sample was used in correcting the results. Explanations of corrections applied to oil distilled and total recovered oil follow Table 1.

As shown in the tables, the percentage of oil distilled, regardless of the quantity, varied rather uniformly with the gravity. For the usual procedure and glass wool, the average value was 87, 93, 96, and 100 per cent distilled from 14°, 22°, 34°, and 56°A.P.I. oil, respectively. The mean deviation from each average did not exceed 1 per cent, while the extreme deviation was only 2 per cent. Furthermore, the values obtained with the heaviest oil at a pressure

of 4 mm. were only 5 per cent lower than those obtained at the usual pressure (1.5 mm. Hg).

As expected, the percentage of oil collected in the trap was quite erratic and could scarcely be used as a basis for the determination. On the other hand, the total weight of oil recovered in the trap and in the distilling tube was quite consistent, and consequently offers an independent method of determining core oil.

The oil recovered, as determined on the basis of total recovery of water, is probably the best method for computing the true oil recovery, since this assumption undoubtedly is more accurate than is the estimation of the volume of water recovered. On this basis, the total weight recovery of oil from samples of at least 0.27 gram contained in glass wool averaged 82, 89, 91, and 76 per cent for the oils in the order listed above. The figures in the table that were omitted in determining these averages, have been enclosed in parentheses. However, for the two runs at the higher pressure, the figures (85 and 83 per cent), obtained by correcting for the effect of the higher pressure upon the percentage distilled, were included in the average.

Especially at the higher gravities, the percentage error involved in determining the total weight of recovered oil was rather high for purposes of calibration. Accordingly, the results with larger samples given in the next section were used in computing the corrected weight of recovered oil (O'_r). As determined more accurately there, the total weight recovery is 84, 89, 95, and 89 per cent at 14°, 22°, 34°, and 56°A.P.I., which values were used in computing the last four rows of each part of Table 1.

The oil-water ratio, as computed from either the weight of oil distilled or total weight of oil recovered, agreed exceedingly well with the true ratio. Of nine measurements at the critical, only one deviation

(-0.01) was found in the former comparison. Furthermore, even at three times the critical oil-water ratio, the average error was only ± 0.01 , with a maximum of -0.04 (at a ratio of 0.56) for a pressure of 4 mm. Hg. Likewise, the comparison at the critical, depending on the total weight recovery of oil, yielded an average error of less than ± 0.01 with an extreme of -0.02 . At three times the critical, the average deviation was ± 0.01 with an extreme of -0.02 . The lower extreme (-0.02) for this method at a pressure of 4 mm. probably was fortuitous.

The accuracy of ascertaining the volume of water collected in the trap is of special interest because it affects the oil-water ratio determined either way. The average error ($W'' - W$) of ± 0.02 , as well as the extreme of -0.05 , is quite in keeping with measurements of volume by graduations of 0.1 milliliter.

The difference ($O'_d - O_o$) between the original weight of oil and that computed from the weight distilled (after applying the average correction factor) was remarkably small. For the regular procedure and glass wool, only two differences, -0.01 and $+0.01$ gram, were found. Of course, the weight distilled could be determined to 0.001 gram (since all the water must have been distilled) and, evidently, there was little variation in the amount distilled from each sample of the same kind of oil.

The oil computed from the total weight of recovered oil could scarcely be expected to agree so well with the known weight, because any error in estimating the volume of collected water causes an equal (absolute) error* in determining the weight of

* With natural core samples, the same error is involved in determining the core oil from the difference in weight of the core. However, it was possible to eliminate this source of error from the calibration tests with glass wool, since the weight of the water added originally could be subtracted from the loss in weight of the glass wool to yield the weight of oil distilled. Likewise, this error might have been eliminated almost as safely from the com-

oil recovered in the trap. Furthermore, the weight of the remainder of the recovered oil depends upon weighings involving the Neoprene stopper. Therefore, at critical oil-water ratios, the mean value of $O'_r - O_o$ of ± 0.01 gram (for the regular procedure and glass wool), as well as the extreme of -0.03 gram, was not surprising.

Oil Distilled from Glass Wool

To gain a more accurate knowledge of the proportion of oil recovered, larger (2-gram) samples of oil were distilled from glass wool. The effect of changes in the conditions operative during the distillation were studied also by including runs in which the temperature was maintained at $700^\circ \pm 40^\circ$ while the pressure was held between 4 and 10 mm. Hg. The data have been listed and labeled in the usual manner (Table 2).

TABLE 2.—*Vacuum Distillation of Oil from Glass Wool*

Crude oil	F		G		E	
	Run 1*	Run 2	Run 1*	Run 2	Run 1*	Run 2
Gravity, deg.	24.2	24.2	43.0	43.0	52.5	52.5
A.P.I.	2.04	2.02	2.03	2.00	2.02	2.02
O_o , gram.	1.90	1.84	2.02	1.99	2.02	2.02
O_d , gram.	93	91	99	99	100	100
O_d/O_o , per cent	1.89	1.84	1.93	1.94	1.84	1.83
O_r , gram.	93	91	95	97	91	91
O_r/O_o , per cent						

* The runs indicated by asterisks were made with the temperature at $700^\circ \pm 40^\circ\text{F.}$ while the pressure was held at 7 ± 3 mm. Hg instead of the usual $700^\circ \pm 25^\circ\text{F.}$ and 1.5 ± 0.5 mm. Hg.

The proportions distilled or recovered from the crudes were not changed appreciably by the variation in the conditions of distillation. It may be recalled also that the change of pressure to 4 mm. for crude oil A (13.8° A.P.I.) lowered the proportion

putation of results in the recovery method (as actually was done in computing the correction factor) by assuming total recovery of water, but the presentation given here was preferred.

distilled by only 5 per cent (Table 1). Even less change was observed in the amount recovered, although probably this was due to the difficulty involved in determining accurately the recovery from small samples.

The percentage distilled from the two extreme oils agreed quite well with the values obtained previously from oils with similar gravities. The oil with the intermediate gravity (43.0° A.P.I.) also yielded results that fitted nicely into the calibration curve.

Fig. 2 includes all of the data that were obtained for the proportion distilled from glass wool by the regular procedure. For the recovery of oil, however, only the data obtained with samples weighing more than one gram were included. For crude oil A, the recoveries of 80 and 78 per cent obtained at the higher pressure were corrected to 85 and 83 per cent and included in the figure.

Oil, or Oil and Water, Distilled from Consolidated Sand

Calibration tests with consolidated sands are very necessary, since they approximate the actual conditions most pertinent to the gravimetric-vacuum method. However, several possible sources of error are inherent in such tests. For example, the exactness of determining the quantities of oil and water in the sample is about one tenth that possible with glass wool or unconsolidated sand, because the former evaluation depends upon the difference between the densities of the two liquids. Other factors are the distillation from the sand of water of crystallization, as well as possibly appreciable quantities of materials (such as carbon dioxide) that escape through the trap. Nevertheless, some such experiments should be conducted to show that, within experimental errors, the results agree with those obtained with glass wool.

TABLE 3.—*Vacuum Distillation of Oil, or Oil and Water, from Cleveland Quarry Sandstone*

Crude oil.....	F	F	D	F	F	F	B
Gravity, deg. A.P.I.....	23.9	23.9	34.0	23.9	23.9	23.9	22.3
O_o , gram.....	0.54	0.67	0.82	1.98	2.01	1.45	1.18
O , ml.....	0.59	0.74	0.96	2.18	2.21	1.60	1.29
W , ml.....	0.00	0.00	0.00	0.00	0.00	1.45	1.75
W' , ml.....	0.06	0.04	0.04			1.50	1.80
W''/W , per cent.....	0.06	0.04	0.04	0.05*	0.05*	1.45	1.75
O_a , gram.....	0.53	0.61	0.76	1.98	2.04	1.44	1.19
O_a/O_o , per cent.....	98	91	93	100	101	99	101
$O_a/O_o = C_a$, per cent.....	+5	-2	-3	+7	+8	+6	+9
O_r , gram.....	0.49	0.63	0.63	1.85	2.01	1.44	1.19
O_r/O_o , per cent.....	91	95	77	93	100	99	101
$O_r/O_o = C_r$, per cent.....	±0	+4	-18	-2	+5	+4	+7

* The values marked with an asterisk were assumed.

The point farthest from the curves as drawn is that for 94 per cent distilled from crude oil D. This value is 3 per cent below the curve, but even if double the difference were to occur, the error introduced at the critical oil-water ratio would amount to only 0.005, causing little concern.

The computation of core oil from the oil distilled or recovered has been facilitated by preparing tables based upon the calibration curves and oil density.

Accordingly, tests were made first (Table 3) in which no water was added to the sand, followed by runs that included additions of both oil and water. The correction for water of crystallization for the latter tests was assumed equal to the average quantity collected from the first three. In the last two tests (including both liquids), the assumption of total recovery of added water was also made in order to compute the original quantity of oil from

the total weight of liquids added to the sample.

The use of the symbols is identical with that of previous tables. The new symbols C_d and C_r represent the distillation correction and recovery correction, respectively.

The first three runs shown in Table 3 were conducted before the electrical heaters had been made, consequently heat from a Méker-type burner was supplied to asbestos tape that surrounded the distilling tubes. Yet the results were sufficiently in accord with those obtained with the regular apparatus. This is seen to be especially true in the light of the fact that the test with consolidated sand shown in Table 1 gave 90 per cent for the value of O_d/O_o .

Apparently, the distillation is not seriously dependent upon the kind, or quantity, of the porous material. The difference between the weight per cent oil distilled and the distillation recovery factor ($O_d/O_o - C_d$) varied from -3 to $+9$ per cent with an average of ± 6 per cent. Similarly, the difference between the total weight per cent oil recovered and the recovery correction percentage ($O_r/O_o - C_r$) varied from -18 to $+7$ per cent, also averaging ± 6 per cent.

From the assumptions and procedures in the tests, the sum of all errors appears in the determination of the oil. Accordingly, the percentage differences discussed represent the differences between the calibration as determined with glass wool and with consolidated sand. These are certainly within the experimental errors involved in the latter method. Furthermore, a rapid method that permits practically independent determinations of the oil contained in small core samples with accuracies of ± 6 per cent constitutes a very valuable tool for analyzing core samples.

Natural Consolidated Cores

In addition to the comparisons given in the foregoing section, one opportunity has

arisen for checking the recently developed method with actual core samples. The data concerned with the oil-water ratio are shown in Table 4, while studies of other properties are given later (Table 6).

The additional symbols D and D' represent, respectively, the difference and corrected difference in weight of the sample, before and after the vacuum distillation. The method of correction is indicated in a footnote to the table. Other symbols and corrections have been explained previously.

TABLE 4.—*Vacuum Distillation of Natural Consolidated Cores^a*

Sample No.	7011	7012	7013	7014
Depth, ft.	7,931	7,932	7,933	7,934
D , gram.	0.44	0.36	0.49	0.74
D' , gram ^b	0.38	0.32	0.44	0.68
W' , ml.	0.18	0.14	0.25	0.40
W'' , ml. ^b	0.14	0.12	0.23	0.37
$O_d = D' - W''$, gram.	0.24	0.20	0.21	0.31
O_r , gram.	0.22	0.25	0.22	0.25
$O_d = O_d/O_o \cdot 0.94$, gram.	0.26	0.21	0.22	0.33
$O_r' = O_r/O_o \cdot 0.92$, gram.	0.24	0.27	0.24	0.27
$O_r'' = O_r'/O_o \cdot 0.90$, ml. ^c	0.29	0.23	0.24	0.37
$O_r''' = O_r''/O_o \cdot 0.90$, ml. ^c	0.27	0.30	0.27	0.30
O_r''/W''	2.1	1.9	1.0	1.0
$O_r' - O_d$, gram.	1.9	2.5	1.2	0.8
	-0.02	$+0.06$	$+0.02$	-0.06

^a Field H, well A.

^b The corrected difference in weight of the sample and corrected water collected were computed from the fact that an extracted and dried core (35.1 gram), adjacent to sample No. 7014, lost 0.079 gram and yielded 0.035 gram of water during vacuum distillation.

^c The gravity of the oil recovered by atmospheric distillation was 32.5°A.P.I. , indicating a gravity for the crude of $25.5 \pm 2^\circ\text{A.P.I.}$ (0.90 ± 0.01 gram/ml.).

The weight of oil in the core, as determined from the difference in weight of the core, agrees sufficiently well with that computed from the total weight of oil recovered. The deviations varied from -0.06 to $+0.06$ gram, with an average of ± 0.04 gram. The weight loss (per gram) and accompanying water of crystallization correction for each core was assumed equal to that of a core adjacent to sample No. 7014. Accordingly, even the extreme deviations appear quite reasonable.

The differences in the oil-water ratios computed by the two methods were relatively large because the ratios were unusu-

ally high. However, deviations in ratios so far above the critical (0.13) are of little consequence.

Calibration Test for the Determination of Permeability, Porosity, and Saturation, Artificial Consolidated Cores

Core samples, with depths roughly corresponding to the oil gravities being studied, were extracted and dried. Air porosities (P_a) were measured in the Kobe porosimeter, air permeabilities (K_a) were determined with the permeameter, and total porosities (P_t) were computed from the bulk volumes measured in the Porosimeter, the dry weights, and an assumed sand specific gravity of 2.68.

The samples were thoroughly saturated with salt water (1000 grams Cl^- per gal.), and then blotted and weighed for the water porosities (P_w). After the cores had been saturated for 20 hr., their salt-water permeabilities (K_{1000}) were measured.

were measured exactly as before. In Table 5, the latter properties have been designated with the addition of primes. Each set of porosity computations was based on the bulk volume measured in the Kobe porosimeter.

The comparisons show that the introduction of relatively large quantities of oil, followed by vacuum distillation, caused little change in the measured porosity; in fact, the divergence of results obtained by the various methods of measuring porosity was much greater than that due to the introduction and distillation of oil.

Air permeability measurements, before and after treatment, did not agree so well. Nevertheless, the ratio of the value obtained after evacuation to the original varied only from 0.95 to 1.61, and averaged 1.22. Since the original permeabilities ranged from 3.8 to 317 md., valuable estimations of air permeability apparently may be made with evacuated cores.

TABLE 5.—Effect of Vacuum Distillation upon Permeability and Porosity

Sample No.....	4594	548	608	3837	3846
Field.....	J	K	K	B	B
Well.....	B	C	D	E	E
Depth, ft.....	3,450	7,747-7,764	8,797-8,806	11,311	11,352
Crude oil.....	B	D	D	E	E
Gravity, deg. A.P.I.....	22.3	34.2	34.2	56.2	56.2
Pore oil saturation, per cent.....	40	40	40	30	50
K_a , md.....	48.9	54.1	140	3.8	317
K'_a , md.....	47.5	54.5	133	6.0	510
K'_a/K_a , per cent.....	97	101	95	158	161
K_a/K_{1000} , per cent.....	575	126	"	146	155
K'_a/K'_{1000} , per cent.....	136	111	126	139	118
K_{1000} , md.....	8.5	43	"	2.6	204
K'_{1000} , md.....	35	49	106	4.3	430
K'_{1000}/K_{1000} , per cent.....	410	115	"	165	212
P_t , per cent.....	22.4	15.7	14.3	17.4	24.0
P'_t , per cent.....	22.3	15.2	14.2	17.6	25.0
P'_t/P_t , per cent.....	100	97	100	101	104
P_a , per cent.....	21.4	13.7	12.4	16.0	21.4
P'_a , per cent.....	20.7	13.5	12.4	16.8	22.5
P'_a/P_a , per cent.....	97	98	100	105	105
P_w , per cent.....	21.0	13.0	12.3	14.3	"
P'_w , per cent.....	19.5	11.9	11.0	15.1	21.0
P'_w/P_w , per cent.....	93	92	90	106	"

* The value obtained for K_{1000} was so high (206 md.) that it appeared the core was disintegrating. However, later measurements point to by-passing between the Neoprene stopper and the core.

* The determination of P_w was vitiated by the introduction of mercury into the core during measurement of P_a .

The various oils were then forced into the cores and the latter were subjected to vacuum distillation. The evacuated samples were weighed and their properties

Water permeabilities represent a different picture. Evidently, enough water of crystallization was distilled from the sands and clays that hydrational effects were

eliminated to a considerable extent and the salt-water permeabilities quite closely approached the air permeabilities. Apparently, extracted samples should be used for measuring water permeability.

Natural Consolidated Cores

Additional evidence as to the reliability of core analysis based on the vacuum distillation was obtained by comparing the properties of the evacuated cores of Table 4 with those of adjacent ones cleaned with chloroform in a Soxhlet extractor.

The previous use of primes to apply to evacuated samples has been continued in Table 6, although in this case the samples were adjacent instead of identical.

TABLE 6.—*Permeability, Porosity, and Saturation of Adjacent Cores* as Determined by Extraction and by Vacuum Distillation*

Sample No.....	7011	7012	7013	7014
Depth, ft.....	7931	7932	7933	7934
O/W ratio.....	2.1	1.9	1.0	1.0
K _a , md.....	45	1.5	4.1	37
K _o , md.....	67	14	8.5	32
P _i , per cent.....	12.2	9.0	12.2	12.0
P _o , per cent.....	12.2	11.2	12.2	11.2
Liquid saturation, per cent.....	31	38	44	39
Liquid saturation', per cent.....	32	36	43	56

* Field H, well A.

Since the properties of adjacent samples are expected to be similar but not identical, the agreement between these sets of data is quite satisfactory. The only important difference appeared in the permeabilities of sample No. 7012 and the adjacent one.

To make sure the samples had been thoroughly cleaned by the extraction process, samples No. 7011 and 7012 were removed from the wax and extracted for an additional 48 hr. The total porosities then amounted to 12.2 and 8.6 per cent while the air permeabilities were found to be 33 and 2.0 md., respectively. Apparently, the original cleaning (4 hr.) had

been quite satisfactory. In fact, the later prolonged cleaning evidently plugged the first core about as much as it opened the second.

Therefore, it would appear that, either sample No. 7012 originally had a higher permeability than the adjacent one, or the distillation caused a large percentage increase in the permeability.

Change in Gravity of Oil during Vacuum Distillation

A knowledge of the gravity of a crude is often helpful to those responsible for the drilling operations, as well as to the analyst. Furthermore, an estimation based on the gravity of the oil collected during the distillation is the only method readily applicable to small samples upon which complete analyses are required.

TABLE 7.—*Gravity of Oil Collected in Trap during Vacuum Distillation*

Crude oil.....	B	F	D	G	H
G _o , deg. A.P.I..	22.3	24.2	34.2	43.0	52.5
O _o , gram.....	0.90	2.02	0.47	2.00	2.02
O _i , ml.....	0.98	2.24	0.55	2.48	2.66
O', ml.....	0.72	1.60	0.35	2.10	2.09
O'/O, per cent.	73	71	63	85	79
G _i , deg. A.P.I..	24.8	25.6	36.2	42.3	51.8
G _i - G _o , deg. A.P.I.....	+2.5	+1.4	+2.0	-0.7	-0.7

In view of this fact, measurements were made with oils collected in the trap, for crude gravities above 22°A.P.I. The data appear in Table 7, including the original weight and volume of oil and volume per cent collected in the trap.

The gravities of oils B and D were measured with the composite of the two largest samples of the respective oils listed in Table 1 that were distilled from glass wool. Accordingly, the quantities of oil and recoveries represent the average for the composite. Part of the data for the runs with the other three oils have been recorded in Table 2.

The new symbols G_o and G_i represent the gravity of the original crude and that of

the oil collected in the trap, respectively. The use of the other symbols has been described previously. Apparently, the gravity of the oil collected in the trap does not differ greatly from that of the original crude, for gravities between 22° and 53° A.P.I. Furthermore, the change does not appear to be very greatly influenced by the percentage collected. The same was true for varying the conditions of the distillation, at least when the recovery did not differ greatly. For example, crude oils F, G, and E were also distilled at $700^{\circ} \pm 40^{\circ}$ F. while the pressure was held between 4 and 10 mm. (Table 2). The volume percentages collected in the trap were 77, 83, and 82, and the gravities were 26.6° , 43.0° , and 50.8° A.P.I., respectively. Thus, none of the gravities differed by more than 1° A.P.I. from those measured with the oils distilled in the usual manner.

There was little need for determining the change in gravity for the crude oil with a gravity of 13.8° A.P.I., since samples containing oils with gravities below about 25° A.P.I. usually are sufficiently large and contain enough oil to permit a direct measurement of the gravity of the crude. However, the two largest samples of the oil shown in Table 1 were composited and the measured gravity was 19.5° A.P.I., representing a rise of 5.7° A.P.I.

The values of Table 7 have been plotted in Fig. 3. A straight line appears to represent the data reasonably well, and the method probably could be relied upon to yield gravities within about 1° A.P.I. of the true ones providing the percentages collected in the trap did not differ greatly from those of Table 7.

Reliability of Oil-water Ratio by Vacuum Distillation

A brief summary of the factors involved in the new method, and the results obtained in the tests, should bring out clearly the possibilities of the innovation.

The volume of core water is taken as the volume of water estimated in the trap, less the water of crystallization lost from the sand. The weight of distilled core oil is taken as the change in weight of the sample, corrected for loss in weight of the sand and diminished by the volume (milliliters expressed as grams) of core water. The weight of recovered oil is assumed equivalent to the difference in the total weight of material recovered and the volume of core water. In either case, the weight of core oil is obtained by allowing for the percentage of oil distilled or recovered. Then, all that remains for determining the volume of core oil is a knowledge, or estimation, of the gravity of the crude.

Thus, the factors influencing the determination of volume of core oil in the former method are: (1) change in weight of sample, (2) loss in weight of sand (other than water of crystallization), (3) volume of water collected, (4) percentage of oil distilled, and (5) gravity of crude. In the recovery method, change in weight of sample is replaced by weight of material recovered, loss in weight of sand (other than water of crystallization) is immaterial, and percentage of oil distilled is supplanted by percentage of oil recovered.

The average error in measuring volumes of collected water was found to equal ± 0.02 ml. with an extreme value of -0.05 ml. As was expected, the change in weight of the sample may be determined with great accuracy, and need introduce no appreciable error. Loss in weight of the sand, in the only case tested thus far, was found (Table 3) equal to 0.2 per cent (0.08 gram), while the volume of collected water of crystallization was 0.1 per cent (0.04 gram) of the weight of the sand. When other factors were eliminated by using glass wool, the percentage of oil distilled from a given oil did not differ from the mean by more than 2, with an average deviation of ± 1 . For samples with oil-water ratios up to three times the critical,

even with crude oil A, the extreme deviation represents less than 0.01 gram. Consequently, this source of error may be neglected. Likewise, the gravity of the crude should not introduce an appreciable error, since estimations from the gravity of oil distilled at atmospheric pressure can be made accurately enough ($\pm 2^\circ\text{A.P.I.}$) so that the error in density will be only about 1 per cent.

Accordingly, the only sources of appreciable error are the estimation of volume of water collected and loss in weight of sand other than water of crystallization. The former should average ± 0.02 ml. and not exceed ± 0.05 ml., and it might be kept much smaller, if worth the effort involved.* The magnitude of the latter error is at present an unknown quantity and, until further data concerning the loss in weight of the sand has been obtained, little can be said concerning it.

Fortunately, this factor is not operative in the recovery method of determining core oil. On the other hand, the determination of the weight of recovered material requires twice as many weighing operations as does that of determining the weight distilled, and two of the weighings involve the Neoprene stopper. For the regular procedure and glass wool, the corrected oil recovered (at critical oil-water ratios), differed from the original oil by the mean value of ± 0.01 gram, with an extreme of -0.03 gram. Although this source of error is not very serious, undoubtedly it could be reduced by a change† in the apparatus.

* For example, the volume of water might be determined by adding a known volume of concentrated salt solution and measuring the final salinity or density of the mixture. If the oil-water interface is anomalous, sufficient accuracy in reading the volume might be attained by flushing out the condensed oil with a clean oil.

† During the distillations, one Neoprene stopper was found to lose 0.029 gram, which is commensurate with the observed deviations. The latter undoubtedly could be eliminated by replacing the stopper with a large ground-glass joint and a thermometer well sealed to the upper part. Providing care was exercised in preventing removal of grease, while in-

Even with the present apparatus, however, the error with a wide variety of oils would probably average no higher than ± 0.02 gram, with an extreme of ± 0.04 gram.

In addition, the computation of oil-water ratio in either method depends upon the estimation of core water. This, in turn, depends upon both the volume of collected water and the correction for water of crystallization. Fortunately, however, uncertainties in these values usually represent a relatively small percentage of the core water.

Allowance may be made in several ways for water of crystallization distilled from the sand. The temperature of the distillation is sufficiently controlled so that the water collected from an adjacent sample, after having been cleaned and dried, should give an accurate measure of the correction. Actual measurement is necessary, however, only when the oil-water ratio is sensitive to reasonable variations in an average correction. If preferred, the procedure might be modified so as to distill the free water at a temperature well below that at which constitutional water is driven from the sand. The distillation could be interrupted at this point and the volume of water recorded before the determination is made.

From the foregoing, it is evident that the method based on material recovered, with indicated refinements, is capable of almost unlimited accuracy. Furthermore, even with the simple apparatus and procedure used in the tests, uncertainties in the oil-water ratios near critical values should average between 0.02 and 0.01* (extreme 0.04 and 0.02)* for gravities between 14 and 56°A.P.I.

The apparatus used for the atmospheric distillation of cores is subject to average

producing and withdrawing the sample, the quantity recovered then could be determined as accurately as can the amount distilled.

* These uncertainties represent the sum of the uncertainties in determining core oil (mean ± 0.02 gram, extreme ± 0.04 gram) and the uncertainties in estimating core water (mean ± 5 per cent, extreme ± 10 per cent).

errors of ± 0.2 ml. in determining core oil. This requires that 3, 2, or 1 ml. of oil with respective gravities of 15°, 20°, or 30°A.P.I. be distilled at atmospheric pressure in order that probable deviations in the oil-water ratio shall not exceed ± 0.02 . In contrast, the ratio may be determined as accurately by the vacuum distillation of only about one tenth as much oil, since the accuracy is about 10 times as great. Thus, the innovation permits a very rapid and accurate determination of the oil-water ratio of a small sample, as well as the rapid estimation of permeability, porosity, and saturation, and should prove a powerful tool for core analysis.

DISCUSSION

(Carlton Beal presiding)

N. VAN WINGEN.*—The authors are to be congratulated on the development of this excellent new procedure for the purpose of establishing fluid saturations. Anyone who has been confronted with the problem of obtaining complete core-analysis data from small wire-line cores can thoroughly appreciate the value of this new technique. It occurs to me, however, that this method may be subject to certain limitations. For example, one of the major features of the new technique is the fact that porosity and permeability tests can be made utilizing the same sample that was used to establish the fluid saturation; in this regard it would seem, however, that for oils of less than approximately 35°A.P.I. gravity, coking during the distillation process might be a factor that may render the samples unfit for subsequent porosity and permeability tests. In addition, as the authors point out, the vacuum distillation samples have a disadvantage in that they cannot be used subsequently to establish water permeabilities because of the distillation of water of crystallization from the sands.

It is pointed out in the article that oil-water ratios can be established by means of this new technique with a considerably higher degree of accuracy than is possible by the conventional

atmospheric distillation methods. It has been our experience that gas-oil and oil-water contacts are generally indicated rather definitely on a qualitative basis by anomalies of the oil-water ratio curve irrespective of the analysis method used to establish the fluid saturations. The practical value of a quantitatively accurate oil-water ratio appears to be subject to some question as the basic data reflect core contamination by the drilling fluid. For example, oil-water ratios for cores taken with oil-base mud will be high, while corresponding values obtained by means of clay-base mud will be low. Thus, it is generally conceded that for obtaining accurate oil saturations a clay-base mud should be used in coring, while reliable water saturations can generally be obtained only from oil-base cores. In view of these considerations, it would seem that the acceptance of any verdict to the effect that a certain sand will produce predominantly water based merely on oil-water ratios may be subject to a considerable hazard factor, and the condemnation of a zone without other confirming data as regards its productive capacity, such as a formation test, would hardly seem to be justifiable, no matter how accurate the oil-water ratios may be.

In view of these considerations, I want to emphasize the point made by the authors that this new saturation technique should not be considered as one that replaces atmospheric distillation, but rather as a complement to the older procedures. The method appears to have its principal value in the special case where a complete analysis (saturation, porosity, and permeability) is desired when only small wire-line core samples are available. Furthermore, I feel that the application should be limited in general to sands containing oil of a gravity in excess of 35°A.P.I.

C. M. BEESON and NORRIS JOHNSTON (authors' reply).—Mr. van Wingen's comments are very pertinent and deserve careful consideration.

Fig. 2 shows that the percentage of crude oil distilled from core samples increases from about 92 per cent at 22°A.P.I. to 100 per cent at 56°A.P.I. That this variation in percentage distilled has some effect upon porosity measured on the residue from the distillation may be seen from Table 5. The introduction and sub-

* Richfield Oil Corporation, Los Angeles, California.

sequent distillation of the crudes with lower gravities tend to decrease the porosity of the core, while the reverse is true for the lightest oil. The latter probably is due to distillation of material such as water of crystallization from the core solids, and to the opening of originally closed pockets in the pore space. As noted in the paper, however, the changes thus effected in the porosity were less than the differences obtained by various methods of measuring porosity, and so are not very serious.

The data of Table 5 indicate that valuable approximations of air permeability may be made from measurements on the residue from the distillation. However, the factor tending to open up pore channels seems more dangerous than does the lack of complete distillation of oil from the pore space. Consequently, the gravity of the crude would probably not be the deciding factor in considering this method for estimating air permeability.

The discussion about the dependence of the oil-water ratio upon the infiltration of drilling fluid is a point well taken. The values listed in the paper as critical oil-water ratios refer only to cores taken with water-base muds under average drilling conditions, and all the known factors should be taken into account for any specific case. With this limitation, however, the oil-water ratio has been found to be indicative of subsequent production. Furthermore, increased accuracy in determining the ratio often increases the accuracy of the prediction. For example, one California field almost invariably produces oil from an interval with an oil-water ratio of 0.08 or higher, and water when the ratio is 0.05 or lower. In this case the accuracy attainable by vacuum distillation has proved to be of utmost value. In addition, predictions based on accurate determinations of oil-water ratios occasionally have made it possible to safely omit expensive and possibly damaging formation tests.

The need for the method certainly is greatest for oil gravities above 33°A.P.I.; for at lower gravities the method based on atmospheric distillation ordinarily is sufficiently accurate. On the other hand, vacuum distillation may be applied to cores containing crude oil of any gravity. If the core is too small for reliable determinations of the oil-water ratio by atmospheric distillation, either vacuum distillation or the more time-consuming method based on

extraction should prove quite satisfactory, regardless of the gravity of the oil.

W. F. CERINI.*—The vacuum distillation method for determination of the oil and water saturation of a core appears to be a rapid method designed specifically for small samples. The gravimetric extraction (A.S.T.M.) method is not considered to be applicable to rapid mass production and, as a result, the distillation at atmospheric pressure by retorting has been used rather extensively even though occasionally the size of the sample has been too small for accurate results.

The atmospheric distillation has the disadvantage in that separate samples are required for permeability and porosity measurements. It is claimed that the vacuum distillation method has the advantage that permeability and porosity measurements may be made on the sample that has previously been subjected to distillation. After distillation, the change in porosity is apparently small and may be neglected; however, the altering of the rock by distillation would seem to appreciably change the permeability. The samples tested indicated that the ratios of the air permeability value obtained after evaluation to the original varied from 0.95 to 1.61 with an average of 1.22. Further testing of additional samples may increase this ratio. This should be further investigated. Water permeabilities on samples that had been vacuum distilled were admittedly not satisfactory because of alteration of the rock.

The determination of the oil content by vacuum distillation is by weight, and this is desirable, since it has been found that a volumetric measurement is practically impossible because of the accumulation of a waxlike material in the receiver. At times, this makes the water determination difficult. The number of weighings required by the vacuum distillation method seems to be offset by the rapid cooling of the apparatus. The present atmospheric distillation involves the use of metal retorts because of the high temperature, therefore, the rate of cooling is slow.

It is recognized that the vacuum distillation method is not a replacement of the atmospheric distillation method; however, it is a useful, additional tool for saturation determinations

* Union Oil Co., Compton, California.

on small samples when speed is essential and knowledge of fluid content is desired.

C. M. BEESON and NORRIS JOHNSTON (authors' reply).—Mr. Cerini has emphasized very clearly the relations between the innovation and older methods of determining the oil-water ratio. In brief, vacuum distillation presents a rapid method of determining the ratio when the sample is small, or, for any other reason, contains too little oil for a determination by atmospheric distillation with the desired degree of accuracy. When speed is of

little significance, the gravimetric-extraction method is very satisfactory for all cases.

There is seldom the need for speed in determining the permeability, porosity, and saturation that there is in obtaining the oil-water ratio. Accordingly, an adjacent sample ordinarily is extracted and used for measuring those properties. Nevertheless, valuable estimations of the properties may be made when they are needed in a hurry, or when the available sample is too small for a complete analysis involving atmospheric distillation.

A Neutron Method for Measuring Saturations in Laboratory Flow Experiments

BY E. BRUNNER* AND E. S. MARDOCK*

(Los Angeles Meeting, October 1945)

ABSTRACT

A method of measuring oil saturations in cores or sand packs by neutron scattering is described. This method permits local saturations to be measured in a core enclosed in a steel pressure vessel without interrupting the flow. Calibration data and a saturation distribution measurement obtained with the apparatus are included by way of illustration.

INTRODUCTION

In laboratory flow experiments designed to study the mechanism of oil production it is frequently necessary to measure the oil saturation in a core or sand pack containing oil, gas, and perhaps brine. It is sometimes desirable that the saturation measurement refer to a relatively small portion of the core, so as to eliminate end effects; that it be made without interrupting the flow, and that it be applicable to a core enclosed in a steel pressure vessel capable of withstanding the pressures encountered in petroleum reservoirs. None of the usual methods of measuring saturation meets all of these requirements. To measure the gas saturation by observing the apparent compressibility of the gaseous phase¹ would require the interruption of the flow and would give an average saturation for the whole core. An electrical conductivity method is available for measuring brine saturations,^{2,3} but it is not applicable to oil. A radioactive tracer might be used if a suitable substance could

be found that would dissolve in the oil, emit gamma radiation, and not be adsorbed on the sand, the steel core holder, or in an aqueous phase. The large gamma-ray background from the mass of radioactive oil in other parts of the apparatus might, however, be undesirable.

There remain for the saturation measurement methods involving the absorption or scattering of some penetrating radiation produced outside the apparatus. It might be possible to use X-rays or gamma rays; but these radiations would be so much less strongly absorbed and scattered by the oil than by the steel walls of the core holder and by the sand that it seems doubtful that much precision could be attained. In a beam of neutrons, however, there is a radiation that is very penetrating and, moreover, its scattering by substances containing hydrogen, such as oil, is qualitatively different from that occasioned by other materials. It would seem possible, and has proved to be quite practicable, to measure oil saturations accurately under the required conditions by means of neutron scattering. The first, to our knowledge, to suggest neutron scattering as a means of measuring oil saturation were F. Brons and J. A. Bottema,⁴ of the Amsterdam laboratories of the Bataafache Petroleum Maatschappij, who made a few preliminary experiments to test the method while they were engaged in exploring the possibilities of neutrons for well-logging purposes.

A comprehensive account of neutrons and their behavior will be found, together

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* Shell Development Co., Emeryville, California.

¹ References are at the end of the paper.

with much related material and many references to original sources, in reference 6, especially section X. Neutrons are particles with no electric charge and with a mass approximately equal to that of the proton, the nucleus of the hydrogen atom. They are believed to be constituents of the nuclei of all atoms except those of hydrogen and are released in many nuclear disintegrations. A convenient source of neutrons is an intimate mixture of radium and beryllium. The alpha particles from the radium and its disintegration products cause the ejection of neutrons from the nuclei of the beryllium atoms. Such a neutron source produces also much gamma radiation, which may disturb the apparatus used to detect the neutrons; but for the present and some other applications, the advantages of availability, small size, and constancy outweigh this disadvantage. The neutron source used in the work described herein consists of a metal cylinder approximately 6 cm. long and 1.8 cm. in diameter, containing 211 mg. of radium (as the bromide) mixed with powdered beryllium metal, and was obtained from the Radium Products Co., New York.*

SCATTERING NEUTRONS WITH HYDROGEN

The peculiarity of hydrogen with respect to scattering of neutrons depends on the masses of the particles involved. The hydrogen nucleus is the lightest of all atomic nuclei and has very nearly the same mass as the neutron. When a fast neutron is scattered by a hydrogen nucleus, therefore, it may lose any fraction of its kinetic energy, up to the whole amount,

and in the average collision it loses one half its energy. Neutrons passing through a substance rich in hydrogen, therefore, are quickly slowed down, and after a time come into thermal equilibrium with the surrounding matter. Neutrons, of course, are also slowed down by collision with nuclei of other atoms; but all common elements other than hydrogen are so much heavier that the neutron can lose only a small fraction of its energy in a single elastic collision, and the process of deceleration is accordingly much slower. The elastic collision of a neutron with a heavy nucleus is analogous to that of a ping-pong ball with a billiard ball: the billiard ball is moved only slightly by the impact, while the ping-pong ball bounces away with nearly its original speed. The collision of a neutron with a proton, on the other hand, corresponds in the same analogue with that of two ping-pong balls: the two balls bounce away with comparable speed and the available energy is shared approximately equally between them. The number of slow neutrons emerging from an object irradiated by fast neutrons, therefore, gives a rough index of the quantity of hydrogen it contains; and this index can be made quantitative if conditions are adequately controlled.

SLOW AND FAST NEUTRONS

The possibility of measuring the flux of slow neutrons in the presence of fast ones depends on the fact that many of the effects produced by neutrons are produced to a much greater extent by slow than by fast ones. Since neutrons have no electric charge, their passage through matter produces no ionization, so that their detection must always depend on secondary processes. Some light elements disintegrate when they are struck by neutrons, and the resultant high-energy-charged particles produce copious ionization in the surrounding material. Boron and lithium are very easily disintegrated by slow

* Radium is dangerous and should not be used without proper precautions. The necessary precautions are discussed at length in the National Bureau of Standards Handbook H-23 on "Radium Protection," obtainable from the Superintendent of Documents, Washington, D. C. The neutrons themselves apparently represent only a minor hazard. Extrapolation of some figures published by P. C. Abersold² indicate that the daily tolerance dose of neutrons would not be received in an 8-hr. day from a source of 200 millicuries strength if the operator remained at a distance from the source greater than about 40 centimeters.

neutrons, and an ionization chamber lined with one of these elements or filled with boron trifluoride gas makes a simple and sensitive detector of such particles. In the presence of an appreciable amount of gamma radiation it is necessary to use a high gain amplifier and count the individual particles, adjusting the recording mechanism to respond only to the relatively large bursts of ionization produced by nuclear disintegrations and not to the weaker bursts produced by gamma rays. Such a counting ionization chamber is perhaps the most sensitive detector for slow neutrons. Its sensitivity is limited, however, when the gamma-ray background is very high; and although such chambers can be made rather small, their size is a disadvantage for some applications.

An alternative method of detecting slow neutrons is to measure the radioactivity (mainly beta) they induce in a suitable material.⁶ By using a substance that is rendered radioactive by slow-neutron capture and which has a suitable half-life, the intensity of a slow-neutron beam may be measured without any difficulties arising from the presence of strong gamma radiation; for the gamma radiation does not affect the induced radioactivity, and the latter can be measured after exposure to neutrons, and at a sufficient distance from the neutron source to avoid any effect of the gamma radiation from that source upon the measuring apparatus. It is this method of detecting slow neutrons that has been adopted in the work described in the following pages. The complete freedom from effects of gamma radiation, together with the small size of the detector itself, which may consist of a thin plate of the sensitive material, combine to allow slow-neutron intensities to be measured at locations in which any other detecting device would fail.

Silver, indium and rhodium have all been used successfully in the present work as detectors of slow neutrons, rhodium

being the most satisfactory. Not only is it necessary that the substance used as detector be strongly activated by slow neutrons, and that the activity decay in a convenient time, but the substance should not be strongly activated by fast neutrons nor by neutrons of intermediate speed. Silver is inferior to the other two metals with respect to activation by fast neutrons, and the softness of indium constitutes a disadvantage for this material. Rhodium has excellent mechanical properties. It has two activities, which decay with half-lives of 44 sec. and 4.2 min., respectively, most of the activity decaying with the shorter half-life, and has proved to be a sensitive detector of slow neutrons.

MEASURING WEAK INDUCED RADIOACTIVITIES

A Geiger-Mueller counter was chosen for the measurement of the weak induced radioactivities because of the great sensitivity of this type of apparatus. We have found no Geiger-Mueller tube that permits entrance of beta rays from an external source and is at the same time as stable as a tube with a thick glass envelope, which is feasible for the measurement of gamma rays. However, by careful control of operating conditions, the measurement of induced beta activities in plates external to the Geiger-Mueller tube has been made with a precision that approaches, though it has never equaled, that expected on statistical grounds from the number of counts recorded.

The apparatus has been used principally with a cylindrical steel core holder 2.6 in. i.d. with 0.5-in. wall thickness, and all measurements on sand packs discussed in this paper were made with such a core holder. As shown in Fig. 1, the neutron source is contained in a lead holder that provides a minimum of 3 in. of lead shielding in all directions except those contained in a dihedral angle of 110° . The neutron source holder is mounted with the un-

shielded side toward the core holder, and at a fixed distance from it, but it can be moved parallel to the axis of the core holder. On the opposite side of the core

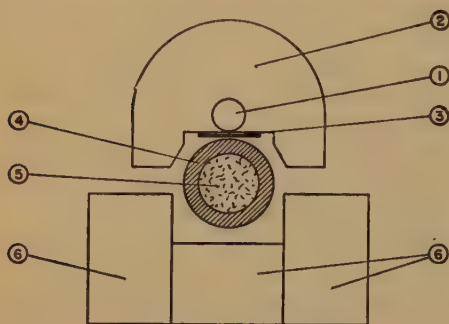


FIG. 1.—ARRANGEMENT OF NEUTRON SOURCE, DETECTOR PLATE, AND SAND PACK.

1. Neutron source.
2. Neutron source holder (lead).
3. Detector plate.
4. Steel-walled pressure vessel.
5. Sand pack.
6. Lead shielding.

holder is placed more lead shielding. The purpose of all the lead shielding is to protect personnel from the gamma radiation produced by the neutron source.

Two rhodium detector plates were used in most of the work. Each consisted of a sheet of rhodium, 5.5 cm. long by 3.8 cm. wide and 0.5 mm. thick, soldered to a steel plate. During exposure to the neutrons, the detector plate is supported by the neutron source holder in a position between the neutron source and core holder, and with its largest dimension parallel to the axes of the neutron source and of the core holder. This position for the detector plate not only affords mechanical advantages over some other possible arrangements, but also allows some information to be obtained about the distribution of liquid in the cylindrical core in a direction perpendicular to the axis.

The rhodium plate is first exposed for 5 min. The choice of exposure time is rather arbitrary, but the time should not be much shorter than the half-lives of the principal activities, nor, for efficient use of time,

much longer than the time during which the activity is measured by the counter. After exposure the plate is quickly removed from the neutron source holder and placed in position near the Geiger-Mueller tube. Exactly 15 sec. after the plate is removed from the neutron source holder, counting is started. The precise timing of this 15-sec. interval is essential to the precision of the measurement because of the rapidity with which the activity decays at first; this timing, therefore, is done automatically by means of a relay operated by a telechron motor. The counting is continued for 3 min. and the number of impulses recorded during that time (less the "background"; i.e., the number of impulses normally recorded in like time when no plate is in the apparatus) is taken as a measure of the activity of the plate. The choice of 3 min. for the counting time was made on statistical grounds: a shorter interval of counting would reduce the precision, because of the smaller total number of impulses recorded, while if the counting were continued longer the background counts, which must be subtracted, would become so large a fraction of the total number of counts as to reduce the precision of the difference. After the activity has been measured, the plate is set aside, the background is measured, and the counts produced by a standard radium source are recorded for control purposes. At the appropriate time, while these auxiliary measurements are still in progress, the exposure of the second detector plate is begun. After the second plate is run the first is run again and so on. About $\frac{1}{2}$ hr. elapses between two exposures of the same plate. This time allows the activity with the longer half-life to decay to less than one per cent of its initial value; and since most of the activity decays much more rapidly, the error caused by the activity remaining in the plate from previous exposures is negligible. For most of the work, six such runs—three with each

plate—would constitute a measurement of saturation. The number of impulses received from an activated plate and the background ordinarily led one to expect

kerosine in a sand pack contained in a calibration vessel of the same diameter, wall thickness, and steel composition as the core holder used in flow experiments is shown

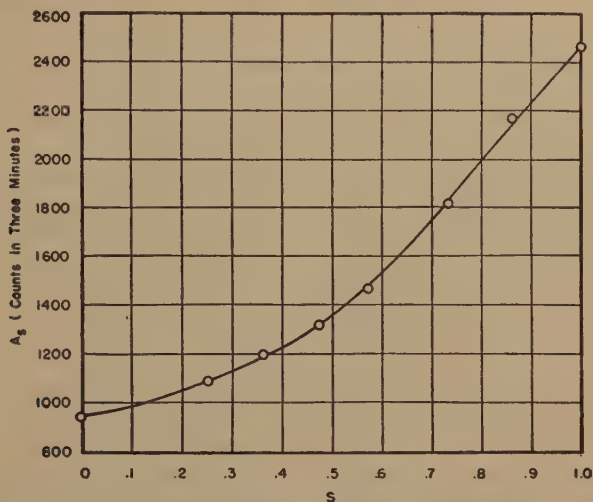


FIG. 2.—CALIBRATION CURVE FOR UNCONSOLIDATED SAND PACK SATURATED WITH AIR AND KEROSENE.

on statistical grounds a probable error of about 0.75 per cent in the measured activity of the plate from such a set of six runs, which, because of the nature of the calibration curve, corresponds to an error of perhaps 1.5 per cent in the saturation. Our measurements have not usually been so reproducible as these figures indicate, but the actual probable error of a saturation measurement made with our apparatus appears to be not more than about 2 per cent. This additional error probably is to be ascribed largely to the remaining instability of the Geiger-Mueller tube.

CALIBRATION

The neutron method of measuring saturations is not an absolute method and must therefore be calibrated: the relation between the activity of the detector plate and the saturation of the core or sand pack must be determined empirically. A calibration curve obtained with

in Fig. 2. The saturations were obtained by weighing the calibration vessel, which is only one foot long and therefore light enough for the purpose. The ordinates give the average number of counts above the background recorded in the 3-min. counting interval for a single rhodium plate exposed in the standard manner. Each point represents an average of eight separate runs.

The activity observed at zero saturation is a considerable fraction of that obtained with the pack fully saturated (Fig. 2). This large activity at zero saturation reduces the precision of the measurement and should be kept as small as possible. Since fast neutrons from the source may be slowed down and returned to the detector plate by wooden furniture, walls, and other objects, the apparatus should be kept as far as possible from them. In addition, the detector plate was shielded from such extraneous slow neutrons by plates of fused boric oxide or other suitable

material; such shielding produced no appreciable improvement with our apparatus, however, and was abandoned. It would appear that most of the activity at zero saturation is due directly to the fast neutrons themselves. This zero effect is considerably reduced if the detector plate is exposed on the opposite side of the sand pack from the neutron source rather than between the source and the pack, as when the data for Fig. 1 were obtained. The reduction in total activity, however, cancels most of the gain in precision resulting from the lower zero effect. The zero effect is considerably worse when silver is the detecting material than when it is rhodium or indium.

In using the calibration curve it is convenient to plot against the saturation not the observed activity A , itself, but rather the fraction $\alpha = (A_s - A_0)/(A_1 - A_0)$, which may be called the relative activity. Here A_s represents the activity observed in the detector plate after it is exposed in the standard manner when the saturation in the core is S ; A_1 therefore represents the activity obtained at 100 per cent saturation and A_0 the activity obtained with the core dry. The use of the relative activity instead of the activity itself permits one easily to allow for small differences between the calibration pack and the pack used in the flow experiment and between different portions of the latter. This is done simply by reducing each measured activity to relative activity by means of values of A_0 and A_1 previously obtained at the same location on the experimental pack. In this way, too, the saturation can be measured, at least roughly, very close to the end of the pack where A_1 is smaller than it is farther in. Differences between calibration pack and experimental pack must still be kept small, of course, because this use of the relative activity amounts only to a linear interpolation that may not be strictly justified.

The calibration curve of Fig. 2 is shown

in Fig. 3 as a plot of relative activity against saturation. The data of Fig. 2 are represented by the lowest of the three curves of Fig. 3. These data were obtained with the calibration pack, whose permeability was approximately 36 darcys mounted horizontally and with the neutron source and detector plate mounted above the pack. The highest curve of Fig. 3 was obtained with the same calibration pack but with the neutron source and detector plate mounted below. As might be expected from the large permeability, considerable gravitational segregation of liquid and gas occurred in this pack at nearly all saturations. Such segregation obviously is important in flow experiments and in the analysis of reservoir behavior, and it is a considerable advantage of the neutron saturation method that it enables one to detect the presence and estimate the magnitude of the segregation. If the segregation occurs during flow to the same extent as under static conditions, and this appears to occur at least sometimes, the neutron method should give the average saturation over a cross section of the pack provided the relative positions of neutron source, detector plate, and pack are the same during measurement as during calibration; and any considerable change in the amount of segregation with flow conditions can be detected by comparing the apparent saturations obtained with the neutron apparatus above or below the pack, using each time the appropriate calibration curve.

If the object of study is not the segregation itself, but some specific property of the pack, it is necessary (at least with a very permeable pack) to mount the pack with its axis vertical. It then becomes something of a problem to locate the correct calibration curve. The difficulty involved here, it may be noted, is not peculiar to the neutron method of saturation measurement but would arise no matter how the saturation were measured. The proper

calibration curve clearly lies between the upper and lower curves of Fig. 3. With a sand pack, or at any rate with a consolidated core, of sufficiently low

with each fluid to the hydrogen content of the pack. The mean free path of slow neutrons in paraffin varies with the energy from about 3 mm. for thermal neu-

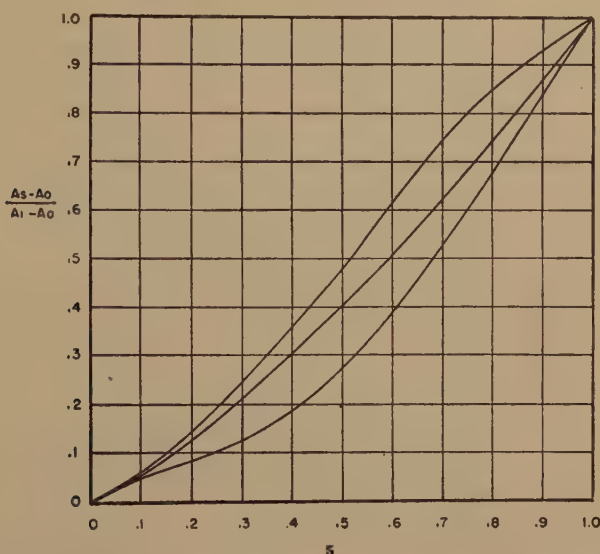


FIG. 3.—CALIBRATION CURVE FOR UNCONSOLIDATED SAND PACK SATURATED WITH AIR AND KEROSENE.

permeability, these two curves should lie so close together as to locate the proper calibration curve with sufficient accuracy. When they are not close together, some other method of locating the calibration curve must be used. For instance, if the saturation measuring device is sufficiently local in its response, a vertical pack might be allowed to come into equilibrium under the influence of gravity, readings could be taken at various points along the pack, and the true saturations determined at these locations by sampling or dismantling the pack.

The fact that the saturation measurement by means of neutrons is essentially a measurement of hydrogen content suggests another method of locating the true calibration curve for the neutron apparatus: namely, to saturate the pack completely with various fluids of differing hydrogen content and to refer the activity measured

trons to nearly one centimeter for neutrons of somewhat greater energy.⁶ Since these distances are large compared with the size of a droplet of oil in a partly saturated pack, no difference in activity would be expected to arise because in one case the hydrogen is concentrated into droplets of oil and in the other it is dispersed uniformly throughout the pore volume. The only apparent source of error in this method lies in the differing chemical nature of the various substances used to obtain the different hydrogen contents. It is this method that was used to locate the middle curve of Fig. 3. The data used are shown in Fig. 4, where they are plotted on log-log paper because the relation between hydrogen content and relative activity appears to be expressed by a simple power law. The ordinates in Fig. 3 represent relative activities calculated with the value of A_1 obtained with kero-

sine, while the abscissas give the ratio of the total hydrogen content of the pack to its hydrogen content when completely saturated with kerosine. Although only

much smaller energy. The disposition of the points on Fig. 4 suggests that the points obtained with the same or closely similar substances tend to lie on a straight line

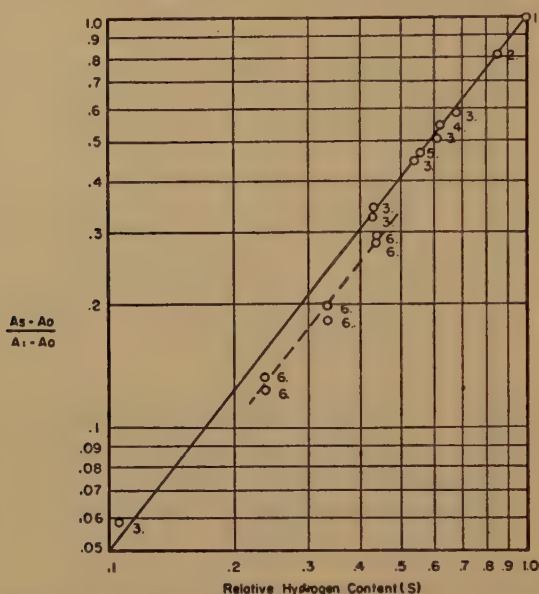


FIG. 4.—RELATIVE ACTIVITY VERSUS RELATIVE HYDROGEN CONTENT.

Obtained by completely saturating pack with different hydrocarbons and comparing their activities and hydrogen contents with those of kerosine.

1. Kerosine.
2. Isopentane.

3. Ethane.
4. Toluene.

5. Benzene.
6. Ethylene.

hydrocarbons were used in order to minimize the chemical differences between the saturants, it is evident that even these differences appreciably affect the result. Since the aromatics benzene and toluene give approximately the same activity for a given hydrogen content as does the saturated aliphatic ethane, and the unsaturated ethylene gives lower activity, it is clear that something other than the carbon-hydrogen ratio is involved. Presumably the important factor is the effect of chemical binding on the neutron-scattering cross section, which becomes appreciable at neutron energies less than about one volt.⁶ The resonance levels of rhodium for slow-neutron capture lie close to this limit, and a large fraction of the activity is due to thermal neutrons of

in such a plot, and that the lines so obtained for different substances or different classes of substances tend to be parallel. If this suggestion corresponds with the facts, the solid line on Fig. 4 would be the proper calibration curve for kerosine; accordingly, it is this line that has been replotted on Fig. 3 as the middle curve. It seems reasonable to believe that this curve is in fact very close to the true calibration curve, but further investigation of the effect of chemical differences between different saturants on the calibration curve is necessary before a definite opinion of its accuracy can be formed.

EFFECT OF MORE THAN ONE PHASE

If the neutron saturation apparatus is to be used at various pressures with a

two-phase hydrocarbon system—as, for instance with oil and natural gas—it is necessary to take into account the effect of the gas as well as the liquid in producing

the brine phase, for instance, might be determined by electrical conductivity.^{2,3} It would be necessary to calibrate the neutron apparatus with all three phases

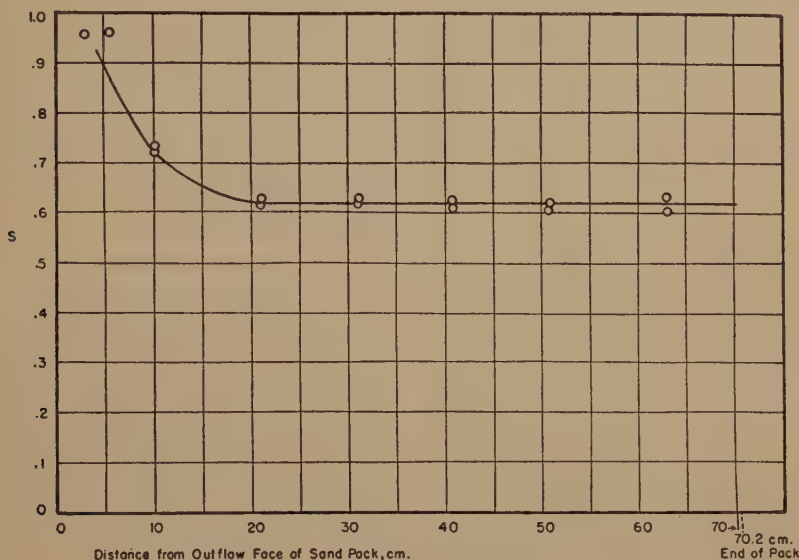


FIG. 5.—SATURATION DISTRIBUTION IN HORIZONTAL SAND PACK.

slow neutrons. Since the gas density varies with the pressure, a separate calibration curve will be required for each pressure. If the compositions and densities of the phases are known for the system as functions of the pressure, the calibration curve for any pressure can be calculated from that at atmospheric pressure by using the assumption that the activity is a function of the hydrogen content only. When the greatest possible accuracy is required, the calibration curves so calculated should be checked at a few pressures to determine the effect of the different chemical natures of the two phases. This is possible, of course, only when the conditions can be so controlled that no considerable segregation occurs.

When three phases are to be present simultaneously (as, for example, oil, gas, and brine) the saturation of one of the phases must be measured independently of the neutron method. The saturation of

present; and, in the example, to obtain curves of oil saturation versus activity for all possible brine saturations. These curves could again all be calculated roughly from one of them by means of the hydrogen-density assumption, and corrections could be obtained at a few brine saturations. The corrections presumably would be much more important in this case than in the case of two hydrocarbon phases because of the greater chemical difference between the phases.

LOCAL SATURATIONS

A useful feature of the neutron saturation apparatus is its specific response to local saturations, which permits the saturation distribution along the length of a core to be accurately determined provided the gradients are not too steep. In order to obtain a definite idea of the resolving power of the apparatus for local saturations, an attempt was made to locate the

level of kerosine in the partly filled, vertically mounted core holder. In this experiment there was no sand pack in the core holder. The activity given by the neutron apparatus was determined as a function of the distance of the center of the neutron source and the rhodium plate above and below the level of the kerosine surface in the core holder. The resultant curve was symmetrical and was well represented by the equation

$$A = B + C \tanh kx \quad [1]$$

where A represents the activity of the rhodium plate, x denotes the distance of the plate and neutron source below the level of the kerosine surface, B and C are constants, and k , the constant that determines the shape of the curve, has the value 0.325 cm.^{-1} . As a measure of the resolution, we may take the distance x_1 from the kerosine level at which the activity attains the halfway mark between its value at the kerosine level and its value far from that level. This is given by $\tanh kx_1 = \frac{1}{2}$ and amounts to 1.7 cm. , or $\frac{3}{4}$ in. It might be possible to obtain even greater resolving power by mounting the neutron source with its axis perpendicular to the axis of the core holder. It is doubtful, however, that a very great increase in resolving power would be obtained; for reduction in the length of the rhodium plate exposed from 5.5 to 2 cm. did not appreciably affect the value of k in Eq. 1, although it reduced the values of the constants B and C by about 50 per cent.

An example of saturation distribution measured with the neutron apparatus is given in Fig. 5, which shows the saturation at various points along a 36-darcy sand pack in the steel core holder. The pack was mounted horizontally and was in equilibrium at approximately atmospheric pressure with kerosine and air flowing at rates of 0.0725 and $1.28 \text{ cu. cm. per sq. cm. per min.}$, respectively. The saturations were measured with the neutron apparatus

above the core holder, and as a calibration curve obtained under the same circumstances was used, the saturations given should represent the average saturation in a cross section of the core. The rise in liquid saturation near the outflow face demanded by the boundary conditions⁷ is clearly to be seen. The shape of this saturation rise, of course, is in this case greatly influenced by the considerable gravitational segregation of liquid and gas that occurred.

ACKNOWLEDGMENTS

The authors wish to express their appreciation to Dr. A. G. Loomis, Associate Director of the Shell Development Company's laboratories, and to the engineers of Shell Oil Co., Inc., for their support of this work; and to Messrs. H. M. Knapp and C. Z. Morgan for their assistance in performing many of the experiments.

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DISCUSSION

(G. H. Fisher presiding)

H. G. BOTSET.*—Have you ever considered using ionization instead of direct count?

E. S. MARDOCK (author's reply).—We have considered using an ionization chamber but the small B-ray intensities encountered were believed to make this method of measurement

* Gulf Research and Development Co., Pittsburgh, Pennsylvania.

impractical. We are still considering the use of an ionization chamber filled with boron trifluoride or lined with lithium, in which the individual pulses produced by the alpha particles are counted.

H. G. BOTSET.—A counting meter or actual count?

E. S. MARDOCK.—Actual count.

E. R. BROWNSCOMBE.—Do you distinguish between water and oil?

E. S. MARDOCK.—No, we cannot distinguish between water and oil. For water we would have to use some other method, such as conductivity.

Effect of Arsenates on the Viscosity of Drilling Muds

By B. C. CRAFT,* MEMBER, AND C. M. MONCRIEF,† STUDENT ASSOCIATE, A.I.M.E.

(Houston Meeting, October 1945)

ABSTRACT

A bentonite-clay drilling mud when treated with tetrasodium pyroarsenate underwent substantially the same reduction in viscosity and water loss as when treated with the complex phosphates. The complex arsenate showed a slightly higher reversion after heating; the other arsenates showed poor viscosity-reducing properties.

INTRODUCTION

During the past 10 years the chemical control of drilling mud has become of major importance in affecting the successful drilling and working over of wells. The desired properties of drilling mud have been well established, and in obtaining these characteristics there has developed a large market for viscosity-reducing chemicals.

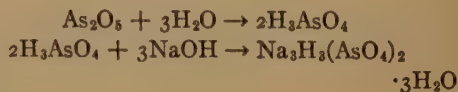
Viscosity reduction produced by humic acid, tannic acid, sodium silicate, sodium tannate, Calgon, and the complex phosphates has been described by Loomis, Ford, and Fidiem.¹ The effects of treatment with complex phosphates and ammonium polyphosphates on the rheological properties of muds were investigated by Fancher² and the alkali vanadates have been described by Williams.³

LABORATORY INVESTIGATIONS

It is the purpose of this paper to point out the effects of arsenates in controlling

the viscosity and gelling characteristics of a drilling mud. Viscosities and gel strengths were measured at room temperatures with a Stormer viscosimeter calibrated in centipoises and operated at 600 r.p.m. Water loss was determined at 80°F. with the Baroid low-pressure wall-building tester at a pressure of 100 lb. per sq. in. for 30 min. The hydrogen-ion concentration was measured with a glass electrode. The bentonite-clay suspensions were prepared in the laboratory and allowed to age several days before testing.

Members of the Arsenic Group in the Periodic Table include arsenic, antimony and bismuth, but this investigation was limited to arsenic. Phosphorus also occurs in Group V of the Periodic System and phosphorus and arsenic form many closely related compounds such as PH_3 and AsH_3 , P_2O_5 and As_2O_5 , H_3PO_4 and H_3AsO_4 . Samples of tetrasodium pyroarsenate were prepared by fusing c.p. disodium arsenate ($\text{Na}_2\text{HAsO}_4 \cdot 7\text{H}_2\text{O}$). According to Friend,⁴ this re-forms the orthoarsenate on dissolution in water. Sodium trihydrodiorthoarsenate was prepared as described by Mellor,⁵ from arsenic pentoxide as follows:



Sodium dihydrogen orthoarsenate (NaH_2AsO_4) was obtained by fusing together equivalent quantities of arsenious oxide and sodium nitrate, dissolving the residue in water and allowing it to crystallize.

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* Professor of Petroleum Engineering, Louisiana State University, Baton Rouge, Louisiana.

† Instructor in Petroleum Engineering, Louisiana State University.

¹ References are at the end of the paper.

According to Mellor,⁵ the other complex arsenates such as sodium hexametarsenate and sodium acid pyroarsenate, are not formed by fusing sodium dihydrogen orthoarsenate. Fusing this compound forms

phosphate with the same suspension are included. This table also shows the effect of chemical treatment on gel strength and filtration. Table 2 shows the viscosity-reducing effect on another bentonite-clay

TABLE 1.—*Effect of Chemical Treatment with Six Per Cent Solutions on Physical Properties of Bentonite-clay Mud*

Amount Added, C.C. per 900 C.C. Mud	Viscosity, Centipoises			Filtration Rate, C.C. per 30 Min.	Stormer Viscosimeter Gel Strength, Grams		
	$\text{Na}_4\text{As}_2\text{O}_7$	$\text{Na}_2\text{H}_2(\text{AsO}_4)_2 \cdot 3\text{H}_2\text{O}$ Fused	$\text{Na}_2\text{P}_4\text{O}_{11}$		Initial	10 Min.	pH
0.	60.0	60.0	60.0	18	98	108	7.2
0.5	36.5	34.3	28.0				
1.0	30.0	28.0	17.4				
1.5	25.9	23.7	12.5				
2.0	21.9	20.3	10.2				
2.5	15.0	20.3	9.0				
4.5	11.3	15.9	7.0				
6.5	7.5	13.2	6.5				
8.5	7.5	12.5	6.0				
10.5	7.5	11.7	5.7	9.5-14.5-10	2-7-6	11-19-9	6-5.8-5.8
After heating at 160°F. for 16 hr.	18.1	19.0	14.0		7-8-7	14-29-10	

TABLE 2.—*Effect of Chemical Treatment with Six Per Cent Solutions on Viscosity of Bentonite-clay Mud*

Amount Added, C.C. per 500 C.C. Mud	Viscosity, Centipoises					
	$\text{Na}_2\text{P}_4\text{O}_{11}$	$\text{Na}_2\text{H}_2\text{P}_2\text{O}_7$	$\text{Na}_4\text{As}_2\text{O}_7$	$\text{Na}_2\text{HAsO}_4 \cdot 7\text{H}_2\text{O}$	$\text{Na}_2\text{H}_2(\text{AsO}_4)_2 \cdot 3\text{H}_2\text{O}$	NaH_2AsO_4
0	36.5	36.5	36.5	36.5	36.5	36.5
0.25	17.4	20.3	21.5	34.3	29.3	30.5
0.5	10.2	14.2	19.5	34.3	20.7	24.0
1.0	6.7	6.7	13.2	24.5	19.5	19.5
1.5	5.5	5.5	9.5	20.8	16.3	15.0
2.5	4.7	4.2	7.5	15.0	13.2	12.0
5.0	4.7	4.2	5.5	6.7	9.7	9.0
7.5			4.7	6.0	8.0	8.0
10.0			4.7	5.5	7.5	7.5
pH of 6 per cent solu- tion.....	7.6	5.0	8.6	8.6	6.6	7.0

sodium metarsenate, which dissolves in water to form again sodium dihydrogen orthoarsenate.

CHEMICAL TREATMENT

The amounts of arsenates required to produce maximum reduction of viscosity when added as a 6 per cent solution to a 900-c.c. sample of bentonite-clay mud form the basis for Table 1. For comparison, similar data using sodium tetra-

mud. No correction was made of the effect on viscosity of dilution by the water contained in the treating reagents, since the amount involved is less than one per cent.

CONCLUSIONS

1. Bentonite-clay mud treated with tetrasodium pyroarsenate underwent substantially the same reduction in viscosity and water loss as the complex phosphates.

2. The complex arsenate showed a slightly higher reversion after heating 16 hr. than the complex phosphates.

3. Neither trihydrodiorthoarsenate nor sodium dihydrogen orthoarsenate possesses good viscosity-reducing properties.

4. Since the arsenates are highly toxic, their use would be limited in actual practice.

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Chapter II. Production Engineering

The Engineering of Oil-well Abandonments

BY WILLIAM E. SCHOENECK,* JUNIOR MEMBER A.I.M.E.

ABSTRACT

THIS paper presents the problem of oil-well abandonment as a group of studies involving the compilation of physical well data, the use of special curves, maps, and interpretative procedures, in order that operations can be analyzed and means for reducing costs can be effected.

Methods for the calculation of the economic limit of production and resultant oil reserves are suggested in order that profitable production may be continued and premature abandonment prevented.

INTRODUCTION

PURPOSE

Extensive studies have been made and much has been written on the procedures for prospecting, drilling, completion, production and repair of oil wells, but the writer has long felt the need for a study of the procedure that should be followed when considering the abandonment of a well. The production from numerous well bores of a fluid material (a circumstance peculiar to the oil industry) that is continually decreasing in quantity leads to an increasing ratio of operating cost to production. It is for this reason that oil fields are not abandoned as a whole and detailed consideration of each well is required before

it can be determined whether more is being expended than will be returned on any well or lease in question. It is the purpose of this paper, therefore, to compile, correlate, and present all matters worthy of consideration in the problem of oil-well abandonment; to suggest interpretative procedures based on such compilations, to the end that reliable estimates of reserves and life may be obtained; to show, as a result of such interpretative procedures, the possibilities for corrective measures conducive to economical production, thereby extending both profitable reserves and length of life.

SCOPE AND APPROACH

Compiling data and outlining a study having the complexity of the problem at hand are naturally subject to the personal experiences of one who undertakes the study; however, the chosen approach and grouping of the subject material may be helpful in the consideration of abandonment problems. Consideration has been given to wells that make gas and water incident with the production of oil; but consideration has not been given to either gas wells or condensate-producing wells, for wells of the latter type have sufficient problems to warrant separate investigation. The major subdivisions of this paper—physical considerations and economic considerations—do not imply that either of these phases can be considered independently, but rather that the two are mutually dependent and are the component parts of an engineering study.

* The Ohio Oil Co., Grand Rapids, Michigan.

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Listed for the New York Meeting, February 1945, which was canceled, and presented before the East Texas Section May 8, 1945.

CONSIDERATIONS INVOLVED

PHYSICAL CONSIDERATIONS

Well Records

Completion Data.—Consideration of the physical oil well begins at the time of drilling and any investigation for abandonment should include a search into all development records available. Wells that have been completed more recently will have better records than older wells. Inadequacy of information on old wells should not discourage an investigator from making his search as exhaustive as possible.

Data on drilling of any well consist of drillers' logs, samples, cores, core analysis, electric logs, drilling time, drill-stem testing, mud analysis, and other information. From the completion record of the well, information on the casing and cementing program, perforating, shooting, acidizing, reaming, and the use of liners can be found.

History.—The second type of record that is kept to a greater or lesser degree on each well is the history of production, operation, and repair.

The lease production record is usually a composite of the records for all wells on the lease. Production records on old wells, or wells that have been sold from time to time, may not be available, and for these such information might be obtained from state production records, tax departments, or pipe-line companies. In many cases, periodic tests of individual well production are made, and these are most valuable in determining production decline history.

Unless gas production is sold for fuel or delivered to a plant for extraction of gasoline, it is ordinarily difficult to find records of either periodic or cumulative gas production. However, gas-oil ratios measured at intervals are invaluable and quite usable in determining estimates of total gas production.

Because ordinarily no commercial value is attached to salt water produced with

oil, most information of this type is estimated. Periodic tests of water-producing wells are made where the best operating procedures are followed, and the results obtained furnish excellent data for analysis.

The history of production of paraffin, sand, and salt is likewise invaluable information to have when considering abandonment. Records of lifting equipment operation are not too often available, but in some instances might hold the key to excessively high lifting costs. Records of well repair and workovers bear close inspection for the knowledge of such can be used in determining the feasibility of future repair work in order to continue production and prevent abandonment.

Interpretative Procedures

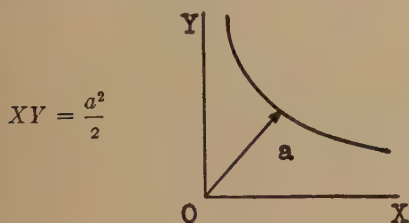
Curves.—The interpretation of the usable data is the most important phase of an abandonment study. The two most simple and fruitful means of analysis are the use of graphical representations of data and trends, and the use of maps reflecting special features of the wells, leases, and fields under consideration.

Plotting of oil production in graphic form, together with the interpretation and use of the resultant trends or curves, is of primary importance. Where production is not restricted, such curves represent the maximum ability of the well to produce from the day of its completion to the time of abandonment and reflect to some extent the physical behavior of the reservoir and well. Curves can be projected into the future with very reasonable accuracy. Cutler's work¹ contains the fundamentals on decline curves. They have both theoretical and practical application only in reservoirs that are predominantly gas drive.

Plotting of periodic production versus time on arithmetic coordinate paper

¹ W. W. Cutler Jr.: Estimation of Underground Oil Reserves by Oil-well Production Curves. U. S. Bur. Mines Bull. 228 (1924) Chap. II, 15-35.

results in the familiar decline curve shown in Fig. 1, which is a hyperbola. The character of the curves on individual wells varies widely, and extrapolations are often difficult, but the following procedure for projection has been devised and has proved relatively successful in a number of cases. The equation for the rectangular hyperbola is:



where X = distance on abscissa,
 Y = distance on ordinate,
 a = distance from origin to point
 where $X = Y$

A family of curves, as illustrated in Fig. 2, can be plotted from this equation by varying the values of a . The plotting of production of various wells on translucent paper, superimposing the zero production line on the abscissa and moving the family of curves either to right or left until the hyperbola most closely agreeing with the production decline is obtained, results in the conformity to actual periodic production curves as illustrated by the two examples in the same figure.

Periodic production plotted versus cumulative production on arithmetic coordinates is also used for predicting future production and length of life. Such a graphical method has no theoretical basis, but it is used because in some cases an apparent straight-line relationship results from the progressively decreasing distances on both the periodic and cumulative scales. This method results in false projections, which are too low, as illustrated in Fig. 3.

The curve of the rectangular hyperbola plotted on logarithmic coordinates is a straight line and extrapolation then be-

comes a simple procedure. Inaccuracies can result from the use of logarithmic coordinates because the projected answer obtained depends upon the choice of position for starting the plotting.¹

An undistorted time scale (abscissa) is preferable for periodic entry of production records. It is the choice of the non-technical executive and is desirable in analyzing small variations in production. Semilogarithmic coordinate paper is also employed because the time scale is not distorted and because such coordinates do tend to straighten out curves, supposedly simplifying projections. A straight line on this type of coordinate paper (Fig. 4) signifies a constant periodic percentage decline, which is not only theoretically incorrect for oil-well production curves but also in practical application leads to the same false projections as in Fig. 3.

Other Graphic Studies.—A graphic representation plotting natural initial production versus acidized initial production is suggested to determine the feasibility of reacidizing old wells before abandonment. Figs. 5 and 6 illustrate examples of such usage. Fig. 5 indicates that there is no relationship between quantity of acid used and the increase in productivity whereas Fig. 6 indicates generally that the use of larger quantities of acid results in better increases in production. Although it appears that there is little reason to expect an increase in production from reacidizing in the case of Fig. 5, these wells in Fig. 6, originally acidized with smaller quantities, might be made more productive by reacidizing in their later life.

Maps.—The behavior of any well is dependent upon the current nature of the reservoir from which it is producing, and even more particularly on the location of the specific well in the reservoir; therefore study should be given not only to the characteristics of an individual well or lease but to the field as a whole, or at least

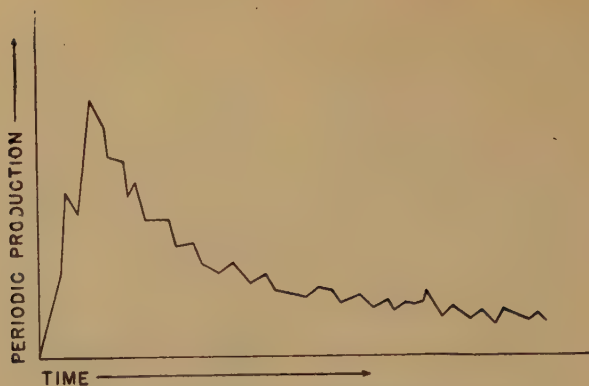


FIG. 1.—PERIODIC OIL PRODUCTION VS. TIME.

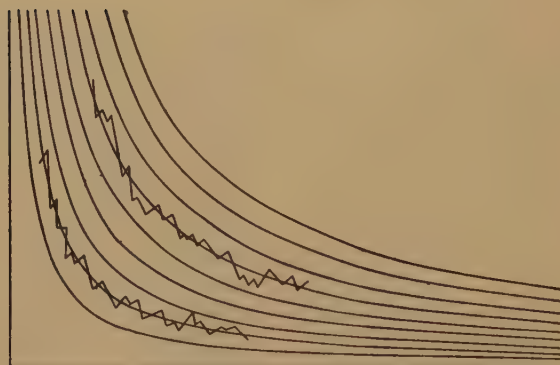


FIG. 2.—FAMILY OF RECTANGULAR HYPERBOLA CURVES.

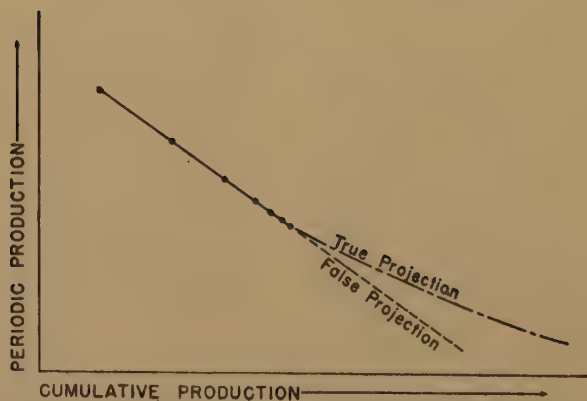


FIG. 3.—PERIODIC PRODUCTION VS. CUMULATIVE PRODUCTION.

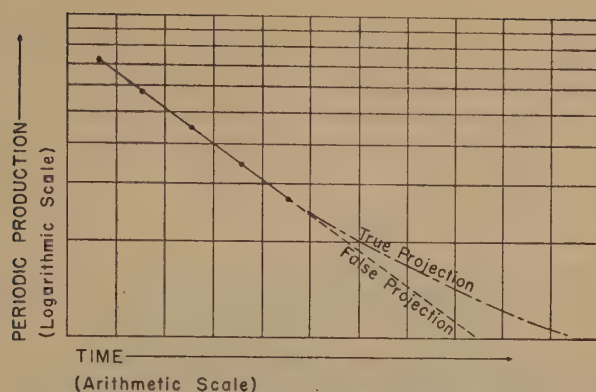


FIG. 4.—PERIODIC OIL PRODUCTION VS. TIME (SEMILOGARITHMIC SCALE).

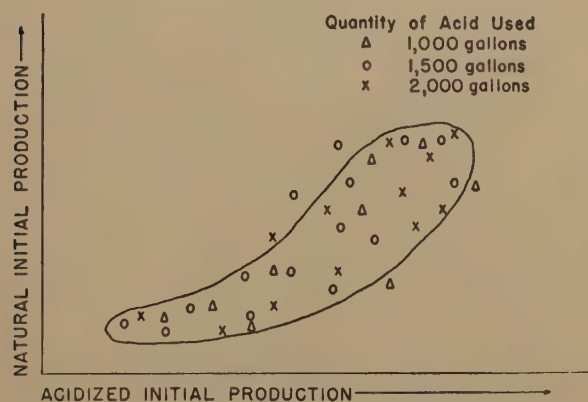


FIG. 5.—NATURAL INITIAL PRODUCTION VS. ACIDIZED INITIAL PRODUCTION.

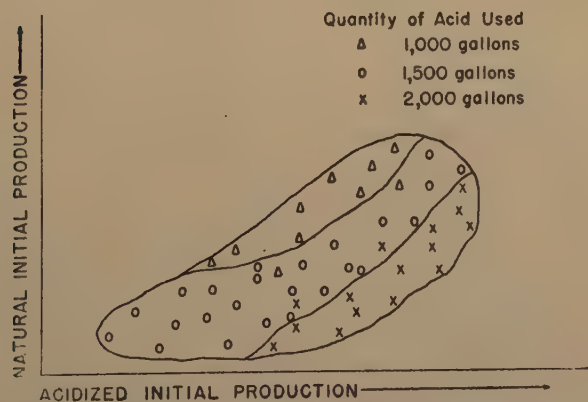


FIG. 6.—NATURAL INITIAL PRODUCTION VS. ACIDIZED INITIAL PRODUCTION.

to a large area surrounding the tract in question. One of the best means for such analysis is to prepare maps that visually correlate and many times explain that

employed is 10 bbl. of oil per day, reflecting a general gradation from the lesser productive areas to the greater productive areas. Little information was available on original



FIG. 7.—DAILY FIELD OIL AND WATER PRODUCTION.

which might otherwise go unanswered. Several types of maps can be used to good advantage, depending upon the nature of the problem.

In the map in Fig. 7, daily oil production and then daily water production are plotted under each well location.² The interval between the isoproduction lines

sand conditions in this particular field. Note that an area of low productivity completely surrounded the portion of the field still productive as of the date of study, and it was concluded therefrom that leases wholly within this area had little chance of maintaining, let alone improving, their production. Some leases under consideration, however, were in areas of both high and low productivity, and it was decided,

² Secondary Recovery of Oil in the United States Chap. XXI, 242. New York, 1942. Amer. Petr. Inst.

after considering the economics involved, to abandon only the wells with the low producing capacity. The map also emphasized that large water production was prevalent only on the edges of the field.

grouped. Such maps aid in determining whether water production in any well is normal or abnormal, thereby contributing to a better analysis of what corrective measures can be employed.

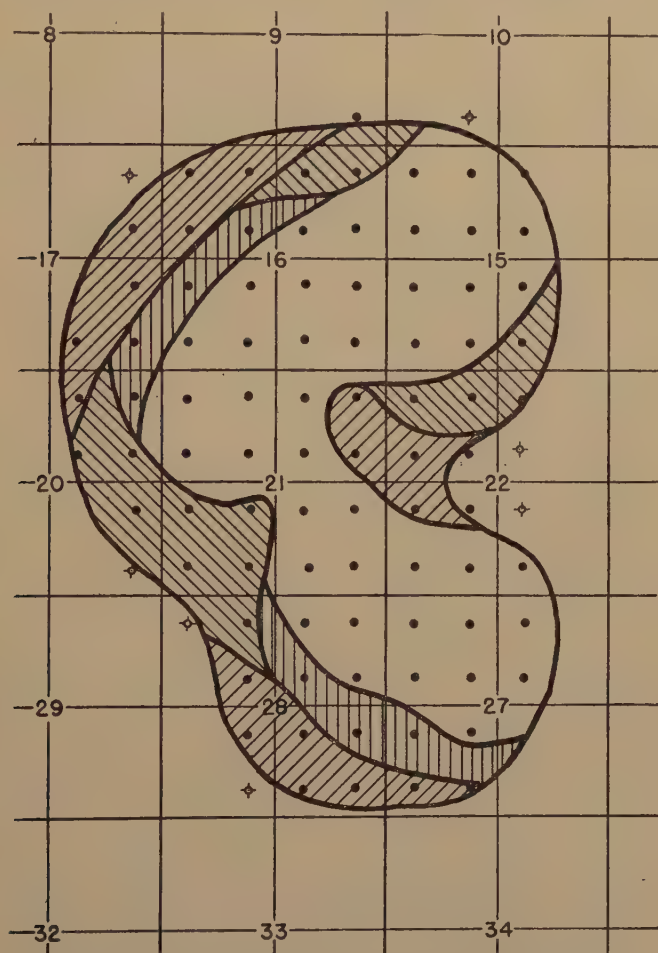


FIG. 8.—WATER-ENCROACHMENT MAP.

The map in Fig. 8 illustrates the general type of map which may be employed to trace the periodic lateral encroachment of water in a field.³ Wells starting to produce water in any one quarter of a year are

Maps of gas-oil ratios, on which the ratios of individual wells are superimposed on a structure-contour map, can be used to determine the general relationship of gas accumulation and any abnormal increase in the ratio of an individual well under consideration for abandonment.

Caution is recommended in the use of maps for recovery per acre or recovery

³ Report of Investigations on a Pressure Maintenance Program for the Reed City Oil Field. State of Michigan, Department of Conservation (1943).

per acre-foot, for they may reflect erroneous conceptions. All wells do not begin production at the same time, therefore recovery

cernible until it is observed in relation to adjacent operations through the use of maps like the one illustrated in Fig. 9.



FIG. 9.—MAP FOR LIFTING EQUIPMENT.

figures on leases developed earlier in the life of a field will reflect not solely the ability of the wells to produce but also the date they were completed. Similarly, if a field has been operating under restricted production, allowables of varying magnitude reflect themselves in recovery totals.

Maps that illustrate the location of different types of equipment installations or grouping of lease labor may reflect causes of either low production or high operating costs, or both. Although this information is available on records, its real significance is sometimes not dis-

Well Repair

After analyzing all data available, it is necessary to ascertain whether any repair to the well or wells can effect sufficient increase in production to continue operation.

Correction of Gas-oil Ratios.—Correction of gas-oil ratio is becoming more successfully applied with increased knowledge of reservoir characteristics resulting from periodic surveys.

Reduction of Water Production.—The commonest repair work attempted in oil wells is plugging off water. The two sources of water intrusion are from the producing

horizon itself and from casing leaks. Ordinarily casing leaks can be repaired successfully but complete shut-off of formation water is problematical and is con-

produced is dependent upon all mechanical equipment from the prime mover to the bottom of the hole. A study of efficiency should determine whether or not the type

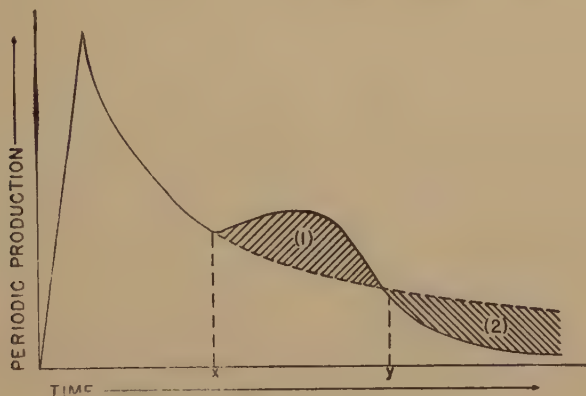


FIG. 10.—EFFECT OF ACID ON OIL PRODUCTION.

tingent on many factors over which the operator often does not have control.

Acidizing.—The reacidizing of old wells in limestone reservoirs is regularly discussed but data for even general conclusions are lacking. The purpose of any method of well repair, including reacidization, is to obtain an additional quantity of oil, the value of which promises to be greater than the monies expended to obtain it; but an immediate increase does not necessarily reflect a cumulative increase. Consider for the moment Fig. 10, which represents a normally declining well production. Such a well is acidized at time x and thereafter produces the quantities as indicated by the solid line. Then, if area 1 is greater than area 2, the venture has been a profitable one but if the reverse is true, the only advantage was an equivalent production of oil in a shorter period of time. If, however, the production follows the normal trend after time y , as represented by the dotted line, there has resulted both a quicker return and an increase in ultimate recovery.

Efficiency of Lifting Equipment.—The operational efficiency of any well artificially

of equipment is best suited to the particular field conditions, and then whether the size of the equipment is sufficient to meet the demands.

Removal of Contaminating Materials.—

In addition to salt water, the three materials encountered most often with the production of oil are paraffin, salt, and sand; the continued production of any one will impair efficiency and, therefore, materially increase the cost of operation.

Alternate Operating Procedures

Production from Other Horizons.—Pursuit of a primary development program sometimes leads to the penetration of horizons that are possibly less productive than the main objective, but that constitute valuable assets when they can be considered as "behind-casing" reserves. Although many such formations might prove noncommercial if separate wells were needed for their development, it is quite possible to recomplete at a minimum cost old wells that are about to be abandoned. Gun perforating can be employed in this type of recompletion. Providing there is not too great a pressure differential

between two or more formations, multiple completions are possible and generally are successful in increasing production. There is also the possibility of retaining the physical well, even after abandonment, for the purpose of deepening to lower productive horizons.

Secondary Recovery Possibilities.—Before the abandonment of any well, lease, or properties, it is of paramount importance that detailed consideration be given to the possibility of secondary recovery operations. The physical history of the operations ordinarily is sufficient background for determining the practicability of secondary recovery, but core analysis made available by the drilling of test wells furnishes the most positive data for any such conclusions.

Possibilities of Water Disposal.—There always exists the possibility that a well can be used for the disposal of salt water from near-by oil wells, either by injection of water into the original productive horizon or by the deepening or plugging back to new horizons.

Vacuum.—Vacuum applied to the casing head in the later life of a well has been employed and has been successful in increasing both the current rate of production and the ultimate recovery.

Miscellaneous

It is desirable to consider, either experimentally or from past operating experience, the effect of the abandonment of any well on the production of oil, gas, and water from an adjacent well or wells. Depending upon the location of the abandoned well and the physical characteristics of the reservoir and the fluids contained therein, experience has shown that abandonments can cause several changes in offset wells: an increase in oil production, an increase in fluid production, or an increase in water percentage with fluid production remaining constant. Because abandonments may have an effect

upon adjacent properties, it is reiterated that the answer to this problem can best be determined experimentally.

ECONOMIC CONSIDERATIONS

Analysis of Operating Costs

Contributing Factors.—The two fundamental contributing factors to the total lifting expense of any well or lease are: (1) labor, (2) maintenance and repair. Cost of labor, a subject large enough to be considered by itself, will not be discussed here. However, if any study shows that the cost of labor can be reduced by more efficient distribution, such change should be made.

Factors contributing to the expense of maintenance and repair are manifold, and unless some means of analysis is instituted the reasons for such expense may be entirely obscured. Report forms are suggested with provision for recording the materials and expenditures necessary as well as the reasons for repair and future preventative measures. Sensible use of such information can materially reduce lifting expense.

The production of large quantities of water may contribute so greatly to the cost of operation as to overshadow other costs. By way of illustration, attention is directed to an analysis of the yearly operating costs of approximately 600 wells in East Texas field, which showed the following costs per net barrel of oil produced:

Pumping water wells.....	\$0.376
Pumping oil wells.....	0.096
Flowing oil wells.....	0.080

The number of producing wells on a lease is likewise a factor contributing to the cost of operation. On a lease with a large number of wells that can be served by a single tank battery and perhaps a central power, the result of such centralization is that a maximum amount of work can be accomplished with a minimum

amount of labor and repairs. Conversely, where a smaller number of wells is served by one battery, the cost per well and per barrel of oil is relatively higher. On Fig. 11

Effect of Well Abandonment.—If the abandonment of a well causes loss of production to a lease, and if no adjustment is made in man-hours to compensate

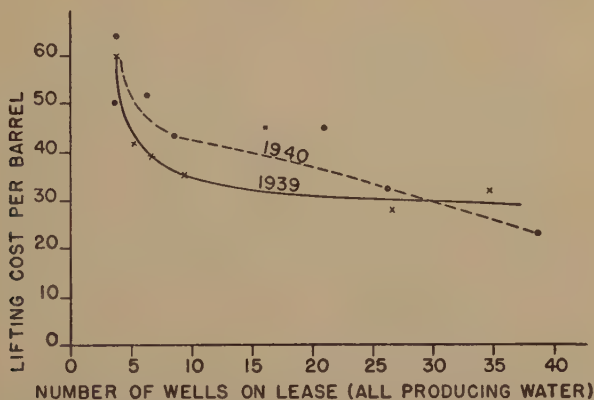


FIG. 11.—LIFTING COST PER BARREL VS. NUMBER OF WELLS ON LEASE.

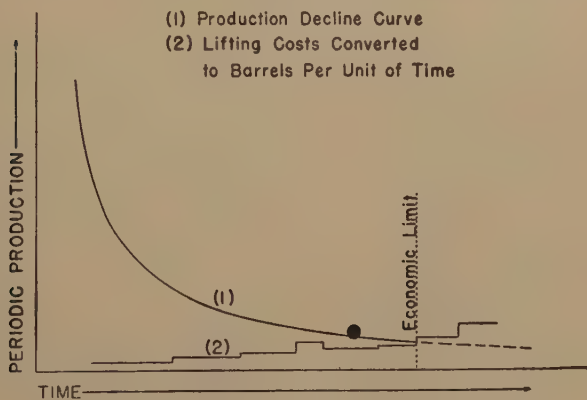


FIG. 12.—PRODUCTION AND COST OF PRODUCTION.

is plotted the lifting cost per barrel of oil versus the number of producing wells on a lease. Seven leases are represented in this analysis, varying from 3 to 39 wells per lease.

Methods of Reduction.—The majority of factors that contribute to unnecessary expense of operation have been tabulated under the heading of physical considerations. Improvements in operation leading to savings in either labor or maintenance and repair, or both, will automatically effect a reduction in operating costs.

therefor, the resultant cost per barrel for the remaining wells on this lease will increase, thereby shortening the economic life of the remaining wells. It is recommended that any economic analysis made preparatory to abandonment consider not only the offending well but also all wells included in a single cost accounting.

Economic Limit of Production and Economic Reserves

Fig. 12 records graphically the production-decline curve 1, and the lifting costs

converted to barrels per unit of time, curve 2. This type of record is suggested so that there may be available a direct visual comparison of volume of production to cost of production. The formula for calculating the lifting costs converted to barrels per unit of time, or the minimum gross production Q necessary to compensate for lifting costs for any well, is as follows:

$$Q = \frac{L}{(P - T)(W)(N)}$$

where L = lease lifting cost per unit time,

P = posted price,

T = taxes,

W = working interest (expressed as percentage of gross production),

N = number of wells on the lease.

This method assumes that each well on the lease contributes equally to the cost of operation; if that is not true, appropriate adjustments should be made. The use of such graphical representation has been found valuable in determining the economic limit of production at the intersection of curves 1 and 2 as well as determining the total remaining economic recovery represented by the area underlying curve 1 to the time of the economic limit.

Only the expenditures of money that would terminate at the time of abandonment of a property are fundamental; charges for overhead, depreciation and depletion should not be considered in determining the economic limit of production and the abandonment of a well. Because of vast differences in financial structure and operation of large versus small companies, the definition of charges directly attributable to lifting expense will vary with the particular organization.

Price of Crude

Unless there are available rather complete and reliable economic analyses that predict future trends in the price of crude oil, the general procedure for the future operation of a property is to consider that there will be no change in the price of crude.

Salvage Values

There are two classifications of salvage values: economic and physical. The former is the net dollars and cents value of the recoverable physical equipment resulting from sale in a second-hand market, and this value is used in obtaining the total net worth of the property. The latter is the value to the operator in transferring the salvageable equipment to another property. Sometimes such a transfer may save new capital investment and lead to a value actually higher than ordinary salvage.

CONCLUSIONS

It is hoped that this paper has accomplished its purpose of compiling, correlating, and presenting all matters worthy of consideration in the problem of oil-well abandonment; of suggesting interpretative procedures based on such compilations, to the end that reliable estimates of reserves and life may be obtained; and showing, as a result of such interpretative procedures, the possibilities for corrective measures conducive to economical production, thereby extending both profitable reserves and length of life.

If consideration is given to all factors suggested, it is believed that greater accuracy will result in the determination of nonprofitable wells, and conversely, that production can be continued in other wells, thereby preventing premature abandonment.

ACKNOWLEDGMENTS

The author gratefully acknowledges the constructive criticisms of Dr. R. E. Sherrill, Department of Oil and Gas Production, University of Pittsburgh, and of Mr. J. D. Wheeler, Chief Petroleum Engineer, The Ohio Oil Co. He also desires to thank The Ohio Oil Co. for the use of records that greatly contributed to the information in this paper.

Precision in Bottom-hole Pressure Measurement

BY E. R. BROWNSCOMBE,* MEMBER A.I.M.E., AND D. R. CONLON†

(Fort Worth and Houston Meetings, October 1945)

ERRORS in measurement of reservoir pressure include: (1) gauge errors, and (2) interpretation errors.

Gauge errors may be reduced by: (a) reading charts with a comparator microscope, (b) use of hard metal stylus points to give clear lines, (c) insuring temperature equilibrium, and (d) making multiple tests. Check calibrations are equally as important as check well tests. A statistical analysis of such check runs shows quantitatively the advantages of a standardized "zero pressure line" and of the use of field calibrations made at bottom-hole temperature on the same chart run in the well.

Interpretation errors include: (a) fluid heads, which should be corrected to the top of the perforations on the basis of well-fluid gravity and from the top of the perforation to the datum level on the basis of reservoir-fluid gravity, and (b) gradients around the well. Conventional shut-in periods may be entirely inadequate to overcome these, necessitating a reservoir study based on build-up curve data, reservoir history, core analysis and any other available information.

Interest in engineering studies of the pressure changes in oil and gas reservoirs is increasing. This type of work yields important information and doubtless will be greatly extended in the future. One of the factors limiting the work, however, is the accuracy with which the reservoir pressures can be determined; for if the inaccuracies in the pressure measurements represent an appreciable percentage of the pressure changes, the engineer is seriously

handicapped, and must delay the reservoir study until the reservoir pressure has changed a relatively large amount. This delay can greatly reduce the benefits of such studies, at least from the point of view of aiding the leasing, drilling and completion programs. Thus, from the point of view of reservoir analysis, it is frequently important to obtain the most accurate pressure data possible early in the history of any field—particularly for the gas-distillate fields now being developed.

This paper deals with improvements in the measurement of bottom-hole pressures that permit pressures even as high as 4000 or 5000 lb. per sq. in. to be determined with gauge errors of only ± 1 to 2 lb. per sq. in. Since pressures out in the reservoir rather than in the bottom of the hole concern the reservoir analyst, differences between bottom-hole pressures and actual reservoir pressures are also considered.

In general, errors in pressure measurement may be divided into:

1. Gauge errors:

- a. Errors due to inaccuracies in reading the pressure charts.
- b. Errors due to irreproducibility of the pressure element and recording system.
- c. Errors caused by failure to allow the gauge to reach temperature equilibrium.

2. Interpretation errors:

- a. Errors caused by a fluid head between the gauge position in tubing and the pressure at the datum level in the reservoir.
- b. Pressure gradients in the reservoir.

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* The Atlantic Refining Co., Dallas, Texas.

† Formerly with The Atlantic Refining Co.; now with Rohm and Haas, Philadelphia, Pennsylvania.

GAUGE ERRORS

The work on gauge errors reported here deals with tests on the $1\frac{1}{4}$ -in. Amerada bottom-hole pressure gauge, which is not

A less skilled operator would probably be able to read to two or three thousandths of an inch (± 6 to ± 9 lb. per sq. in.). Thus this reading error can be appreciable and

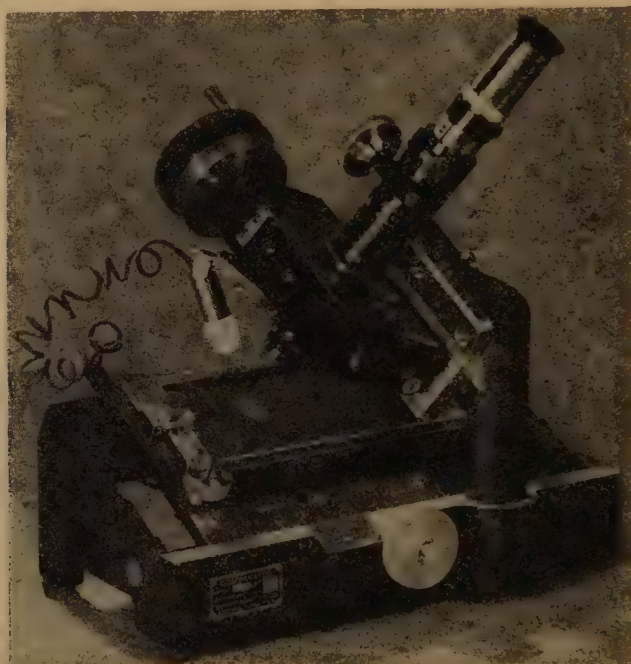


FIG. 1.—COMPARATOR MICROSCOPE FOR READING PRESSURE CHARTS, MODIFIED FROM INSTRUMENT DESIGNED BY GULF OIL CORPORATION.

only a fine instrument in itself but also appeared to be better suited for use at temperatures up to 240°F. than other available $1\frac{1}{4}$ -in. gauges. However, many of the procedures in this paper can be used to advantage with any type of gauge. The magnitude of the errors reported applies to the Amerada gauges used.

*Errors Due to Inaccuracies
in Reading Pressure Charts*

One of the most obvious sources of possible inaccuracy is in measuring on the chart the magnitude of the pressure deflection. Usually a skilled operator can read the pressure deflections to within one or two thousandths of an inch (± 3 to ± 6 lb. per sq. in. for a 6000-lb. per sq. in. gauge).

was one of the first sources of inaccuracy studied.

The Gulf Oil Corporation has developed a traveling microscope of the comparator type (Fig. 1) for use in measuring displacements on the Gulf gauge charts. One of these comparators was modified so that it could be used to measure the 2-in. Amerada deflections. This microscope employs a micrometer screw that makes possible measurements to 0.0001 in., so that in using it one can check the chart deflections to within 0.0002 in. Thus reading errors have been reduced from 3 to 6 lb. per sq. in. to less than 1 lb. per sq. inch.

In order to achieve this accuracy in reading the pressure deflections, it was imperative to have lines on the chart that

were clear and sharp even when viewed under an enlargement of 40 diameters. However, examination shows that the lines ordinarily were not sharp, usually being greater than 0.0030 in. wide (equivalent to 11 lb. per sq. in., Fig. 2). Some improvement was obtained by using black coated charts and steel stylus points instead of the white coated charts and gold stylus points commonly used, but the final solution to this problem was to use stylus points with special noble-metal tips. Such points, known by the trade name of Permopivots, were developed for use as high-grade, long-wearing phonograph needles. For use in the bottom-hole pressure gauges they were found to be far superior to the steel needles, giving a much finer line and needing no sharpening. By use of these new stylus points on copper charts having uniformly heavy coatings and of a microscope to read the charts, the chart deflections were made much clearer (Fig. 3), and not only were the reading errors reduced but also the way was opened for further research on the reproducibility of the gauge.

*Errors Due to Irreproducibility
of Pressure Element and Recording System*

The Amerada gauge produces a chart similar to the sketch shown in Fig. 4. The deflections read are the distances between the base line *A* and the pressure plateaus *B*, *C*, *D*, and *E*. The accuracy of the gauge is influenced not only by the reproducibility of the position of the pressure plateaus but also by the reproducibility of the base line *A*. This base line is drawn manually by manipulation of the chart carrier, after a chart is inserted in the gauge and before the case is made up and the gauge lowered into the well. The position of the stylus arm at the time the base line *A* is drawn depends upon the extent to which the bourdon tube has relaxed following the last application of pressure. Thus the reproducibility of the base line is influenced by the past history



FIG. 2.—TYPE OF LINE FREQUENTLY OBTAINED WITH STEEL NEEDLE.

FIG. 3.—TYPE OF LINE OBTAINABLE WITH NEEDLES HAVING SPECIAL NOBLE-METAL TIPS.

of the gauge and also by the influence of such factors as the jarring it has received on its way to the field. In order to standardize the past history of the gauge and thus

semble Fig. 5. The position of the line drawn at the end of the 7 min. at atmospheric pressure is used instead of the base line. Numerous reproducibility experi-

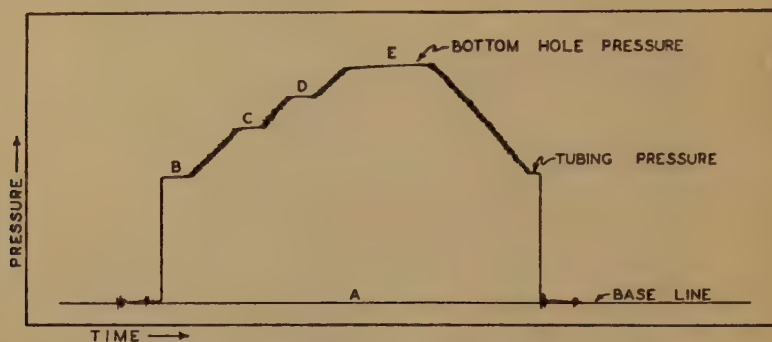


FIG. 4.—CHART RECORDING BY AMERADA PRESSURE GAUGE.

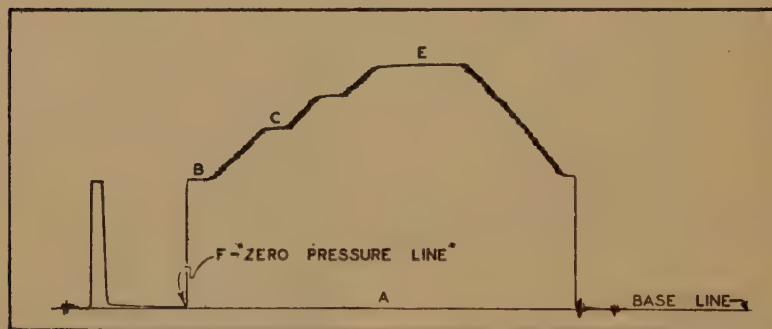


FIG. 5.—USE OF PRELIMINARY PRESSURE TO GIVE ZERO LINE READING BY GAUGE, OBVIATING CERTAIN IRREGULARITIES INTRODUCED BY BASE LINE.

obtain a better atmospheric pressure indication, the following procedure was developed:

Well Tests.—After the gauge is assembled and put in the lubricator, the gauge is subjected to tubing pressure for a period of one minute; then this pressure is vented and the gauge is allowed to remain at atmospheric pressure for 7 minutes.

Calibrations.—Before proceeding with a calibration, the gauge should be subjected to a pressure roughly equivalent to tubing pressure at the field to be tested for one minute and then allowed to remain at atmospheric pressure for 7 min. The resultant pressure-survey chart will re-

ments, some of which are described later in this paper, have shown that the reproducibility of the gauge referred to the "zero pressure line" at point F is definitely better than when referred to the base line A.

Errors Caused by Failure of Gauge to Reach Temperature Equilibrium

As a final note on gauge errors, it should be mentioned that in taking pressures, as well as in making calibrations, it is essential to attain temperature and pressure equilibrium. Tests indicate that this requires from 15 to 20 min. Therefore, in this work

the gauges were left on bottom from 20 to 25 minutes.

*Error Reduction by Use
of Multiple Well Tests and Calibrations*

One rather obvious method of improving the accuracy with which a given bottom-hole pressure can be determined is to take multiple well tests, since the probable error decreases approximately with the square root of the number of measurements made. Thus, if four bottom-hole pressure tests were made instead of one, the probable error of the pressure obtained would be decreased by a factor of about 2. On this basis it certainly pays to carry out at least four pressure measurements whenever a well pressure must be known accurately.

While multiple well tests often are used to improve the accuracy of the bottom-hole pressure measurement, it is not common practice to use multiple calibrations to improve the accuracy of the calibration data. Inasmuch as the absolute accuracy of bottom-hole pressure data depends just as much on the accuracy of the calibrations used as on the well data, and since calibrations are so much easier to obtain, multiple calibrations should always be used. An additional advantage of multiple calibrations arises from the fact that such tests give a good indication of the condition of the gauge. Thus in the course of calibrating the gauge, one has advance information as to the state of repair of the gauge and the extent to which reproducible bottom-hole pressures can be expected. This is an important factor, for gauges do vary considerably among themselves. Also, a given gauge usually varies from time to time, depending on how recently it was overhauled, and upon the age of the pressure element. Unless the multiple calibration tests show the gauge to be satisfactorily reproducible, it should not be used in a survey where a high degree of accuracy is desired.

TYPES OF ERRORS AND REPRODUCIBILITY
FROM PRESSURE GAUGES

In order to understand the type of error involved in bottom-hole pressure measurements, as well as what reproducibility should be expected from the pressure gauges, a statistical study was carried out on a series of well pressures and calibrations. As bottom-hole pressure gauges are ordinarily used, it would have been impossible to make such a study, because usually a gauge is calibrated only once and a given well is tested only once and hence the pressure data are inadequate for statistical analysis. However, during the past year several sets of multiple calibrations and multiple well tests have been made, all with the same gauge. These are given in Table 1, a total of 82 separate measurements being available.

Inasmuch as the different calibrations and different well tests were made at several pressure levels, differing by as much as 20 per cent from the average, it was first necessary to reduce all the data to some common base. This was accomplished by considering each set of calibrations and each set of well tests separately, calculating the mean for each set, and then obtaining the deviations of the various single measurements from the respective means (Table 1). The resultant deviations as calculated from the base line were then plotted in Fig. 6 as a function of their magnitude versus the frequency of their occurrence. In order to aid in evaluating the distribution of these deviations, this same plot also shows a normal distribution curve, which was calculated from the average deviation of all the data. Fig. 6 shows that the deviations in bottom-hole pressure measurements did follow a normal distribution rather closely. By means of this normal distribution it was possible to calculate the probable error; that is, the error of a size that was exceeded by only half the measurements. The calculated value

of ± 4.35 lb. per sq. in. was reasonably close of the values of $+3.4$ and -3.5 , which were the actual values for which one half the errors were larger and one half smaller.

In the course of carrying out this statistical study, a statistical study of the reproducibility of the pressure measurements when referred to the zero line was also made (Table 1). These data are

plotted in Fig. 7. Comparison of Figs. 6 and 7 shows that the reproducibility of the measurements in Fig. 7 was considerably better.

The manufacturers of the bottom-hole pressure gauge describe the accuracy as being within 0.25 per cent of the full scale deflection. Obviously the manufacturer cannot guarantee what a gauge will do if

TABLE 1.—*Reproducibility Tests Used in Figures 6 and 7*
CALIBRATION TESTS

Date	Calibration Pressure, Lb. per Sq. In.	Modulus ^a		Average Modulus		Deviation from Average Modulus	
		To Base Line	To Zero Line	To Base Line	To Zero Line	To Base Line	To Zero Line
Nov. '43.....	2,878.3	3,709.7	3,706.3	3,705.2	3,706.1	5	0
		3,708.0	3,709.0			3	3
		3,710.0	3,705.0			5	1
		3,700.5	3,708.0			5	2
		3,698.0	3,702.0			7	4
		3,707.0	3,704.0			5	2
	3,651.4	3,702.0	3,703.0	3,701.9	3,702.1	0	1
		3,705.8	3,701.3			4	1
		3,698.0	3,704.5			4	2
		3,696.7	3,699.7			5	2
		3,706.0	3,703.0			3	1
		3,702.7	3,702.0			1	2
	4,424.5	3,708.8	3,705.2	3,703.5	3,703.6	5	2
		3,700.0	3,705.0			4	1
		3,700.0	3,703.0			4	1
		3,705.5	3,720.0			6	10
		3,708.0	3,706.0			9	4
		3,702.0	3,714.0	3,699.1	3,710.3	3	4
Dec. '43.....	2,878.3	3,689.0	3,708.0			10	2
		3,691.0	3,707.0			8	3
		3,696.5	3,711.0			1	5
		3,704.0	3,705.5	3,695.5	3,706.0	9	1
		3,690.7	3,705.0			5	1
		3,691.3	3,704.3			4	2
	3,651.4	3,697.5	3,709.5			1	3
		3,703.7	3,705.7	3,696.7	3,706.5	7	1
		3,697.0	3,707.0			0	1
		3,694.0	3,706.0			3	1
		3,692.0	3,704.0			5	2
		3,702	3,695	3,695.5	3,694.6	7	0
April '44.....	2,878.3	3,694	3,694			1	1
		3,692	3,696			3	1
		3,695	3,696			0	1
		3,695	3,692			0	3
		3,697	3,692			4	0
		3,693	3,692	3,692.8	3,692.0	0	0
	3,651.4	3,689	3,691			4	1
		3,693	3,697			0	5
		3,692	3,691			1	1
		3,694	3,690			3	1
		3,692	3,692	3,690.8	3,691.2	1	1
May 44.....	2,878.2	3,688	3,691			3	0
		3,691	3,692			0	1
		3,692	3,691			1	0
		3,688	3,688	3,690.3	3,690.7	2	2
		3,687	3,688			1	0
		3,687	3,687			2	3
	3,651.4	3,684	3,684			1	1
		3,685	3,686	3,686	3,686.3	2	2
		3,686	3,686			1	1
		3,682	3,682			2	1
		3,684.3	3,684.7			2	3
		3,684.3	3,684.7			2	3

^a The modulus is the pounds per square inch corresponding to a deflection of one inch.

TABLE I.—(Continued)
WELL TESTS

Date	Field	Well	Bottom-hole Pressure		Average Bottom-hole Pressure		Deviation from Average Pressure		
			From Base Line	From Zero Line	From Base Line	From Zero Line	From Base Line	From Zero Line	
Nov. '43... ..	I	A	3.507	3.513			10	6	
			3.495	3.505	3.497	3.506.5	2	2	
			3.491	3.504			6	3	
	3.495	3.504	2	3					
	I	B	3.572	3.580	3.576.5	3.582.5	4	3	
			3.579	3.585			3	2	
			3.832	3.832			9	3	
	2	C	3.822	3.828	3.822.5	3.829.5	1	1	
			3.820	3.828			3	1	
			3.816	3.826			7	3	
	2	D	3.871	3.866	3.866	3.866	5	0	
			3.865	3.868			1	2	
			3.862	3.864			4	2	
	April '44.....	I	A	3.511	3.528	3.518.7	3.520.7	8	7
				3.524	3.520			5	1
3.521				3.514	2			7	
I		B	3.541	3.552	3.546.3	3.550.5	5	1	
			3.539	3.549			7	2	
			3.558	3.548			12	3	
2		C	3.547	3.553	3.796.5	3.999.5	1	2	
			3.802	3.801			5	1	
			3.791	3.798			6	2	
2		D	3.839	3.840	3.830.8	3.833.5	8	6	
			3.826	3.835			5	1	
			3.830	3.830			1	4	
May '44.....		2	D	3.828	3.829	3.823.7	3.821	3	5
				3.827	3.827			3	6
				3.827	3.818			3	3
	3.818			3.818	6			3	
Sum of the deviations.....							306	181	
Average deviation [divide by $\sqrt{n(n-1)}$].....							3.75	2.12	
90 per cent error from average deviation (multiply by 2.08).....							7.8	4.4	
Sum of the squares of the deviations.....							1792	675	
Standard deviation (take square root and divide by $\sqrt{n-1}$).....							4.70	2.89	
90 per cent error from standard deviation (multiply by 1.66).....							7.8	4.8	

its precision has deteriorated through use, or if an inexperienced operator is reading the pressure charts. In fact, it is difficult to interpret just what any such "within accuracy" can mean, for it does not state quantitatively the extent to which the error will equal 0.25 per cent or the extent to which the error will be appreciably less than that amount. Therein lies the advantage of a study of the errors such as Fig. 6.

Reproducibility tests (such as shown in Fig. 6) not only indicate the behavior of the gauge but they also provide a means for describing the accuracy of the gauge or of any given set of measurements. For just as it is possible to calculate the probable error, or the average deviation, or the standard deviation, for the measurements shown, so it is possible to calculate, from

bottom-hole pressure data on any series of calibrations or measurements, the likelihood of any error. The probable error is that which any given measurement has a 50-50 chance of exceeding. However, in practical usage it is convenient to assign to a measurement limits of error that are seldom exceeded, rather than limits that will be exceeded half the time. Thus, in describing the accuracy of recent tests, we have adopted the term "90 per cent error," which is that error exceeded by only 10 per cent of the measurements. The relation of this to other errors is:

$$\begin{aligned}
 90 \text{ per cent error} &= 2.46 \times \text{probable error} \\
 &= 2.08 \times \text{average deviation} \\
 &= 1.66 \times \text{standard deviation.}
 \end{aligned}$$

The last two equalities are strictly true

only if the errors follow the normal error curve. If the 90 per cent error as calculated from the average deviation differs sub-

evaluating the precision of the gauge. To compute the 90 per cent error from a set of data by either method, obtain the devi-

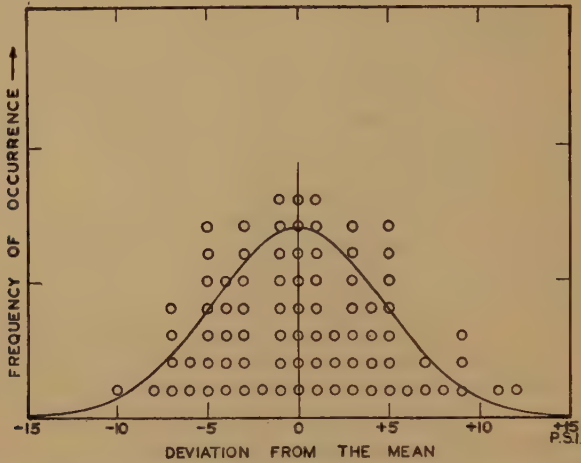


FIG 6.—DISTRIBUTION OF GAUGE ERRORS; PRESSURE MEASURED IN TERMS OF DISTANCE TO BASE LINE.

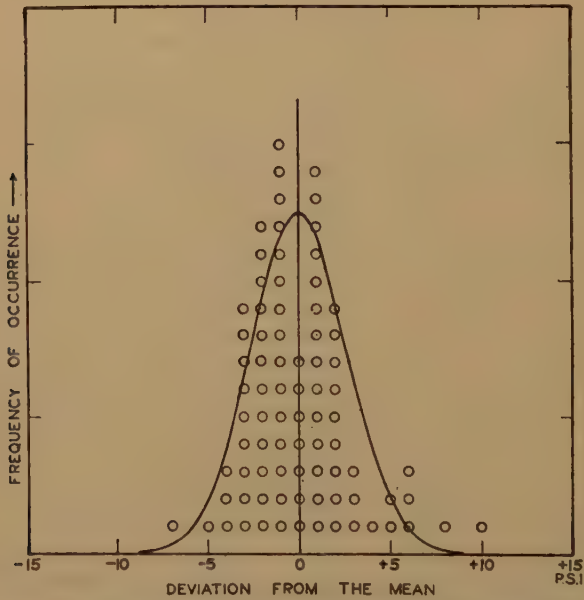


FIG. 7.—DISTRIBUTION OF GAUGE ERRORS; PRESSURE MEASURED IN TERMS OF DISTANCE TO ZERO LINE.

stantially from its value when calculated from the standard deviation, the data usually will not be a reliable basis for

ation of each measurement from the arithmetic average of the set (without regard to plus or minus sign). The 90 per

cent error of a single measurement as calculated from the average deviation is:

$$90 \text{ per cent error of individual measurement} \\ = 2.08 \times \frac{\text{sum of deviations}}{\sqrt{n(n-1)}}$$

As calculated from standard deviation it is:

$$90 \text{ per cent error of individual measurement} \\ = 1.66 \frac{\sqrt{\text{sum of squares of dev.}}}{\sqrt{n-1}}$$

where n = number of measurements in the set.

The 90 per cent error of the arithmetic average of a set of measurements may be obtained from the foregoing in each case by dividing by \sqrt{n} . Thus the data in Fig. 6 indicate a 90 per cent error of 8 lb. per sq. in. for a measurement read from the base line, and in Fig. 7, a 5 lb. per sq. in. 90 per cent error when the zero line is used.

It should be noted that the error figures given here refer only to random errors due to the inevitable failure of results to exactly check each other. Consistent errors, such as may arise from improper operation of the gauge, calibration procedure, etc., are not included. The evaluation of random errors is in general an important step in locating and eliminating consistent errors.

In the foregoing discussions we have tried to show how by elimination of reading errors, by improvement in the reproducibility of the atmospheric pressure line, and finally by use of multiple tests and calibrations, the accuracy of the bottom-hole pressure tests can be greatly improved. In addition to these changes, a procedure has recently been developed by the use of which the reproducibility of bottom-hole pressure measurements has been still further improved. This procedure, which decreases the errors in the pressure measurements by a factor of 2, calls for the use of a portable calibrating bath and a

portable dead-weight gauge, so that the pressure gauges can be calibrated in the field before they are used. In actual practice, the gauge is calibrated at bottom-hole

TABLE 2.—*Reproducibility Tests, Using Field Calibration Technique (Fig. 9)*

Date	Field	Well	Bottom-hole Pressure, Lb. per Sq. In.	Average Bottom-hole Pressure, Lb. per Sq. In.	Deviation from Average
June '44†.....	2	C	3,818	3,817	1 0 0 1 2 0 0 5 2
			3,817		
			3,817		
			3,816		
			3,815		
July '44†.....	2	D	3,815		
			3,817		
			3,817		
			3,815		
			3,808*		
			3,811*		
			3,824*		
			3,821*		
			3,822*		
			3,815*		
3,825*					
Aug. '44.....	2	C	3,825*		
			3,806		
			3,806		
Aug. '44.....	1	B	3,808		
			3,489		
			3,490		
			3,496		
Aug. 15 '44...	3	E	3,494		
			5,711		
			5,692		
			5,703		
Aug. 27 '44...	3	E	5,703		
			5,671		
			5,672		
Oct. '44.....	4	F	3,970		
			3,971		
			3,975		
			3,972		
			4	G	3,972

* n = number of measurements in set = 19.

† These tests were made with a gauge that did not show a good calibration reproducibility. These tests and those for field 3 were not included in estimating the precision.

† These surveys were combined, as field was shut in during interval.

temperature and at a pressure reasonably close to the estimated bottom-hole pressure (within 25 to 50 lb. per sq. in.). This calibration is carried out after the pressure gauge has been assembled and before it is put into the well. After the gauge is taken from the well, it is calibrated a second

time. Fig. 8 shows the type of pressure chart obtained. Reading such a chart is comparatively easy, for the microscope

Several times since this procedure was inaugurated, the accuracy of the surveys obtained has been calculated on the basis

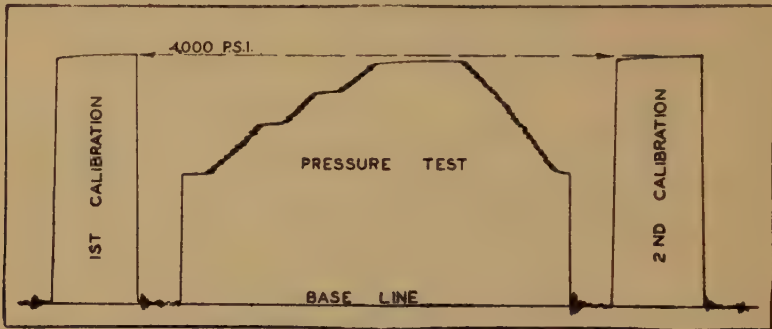


FIG. 8.—CHART OBTAINED WHEN PRESSURE MEASUREMENT IS BRACKETED BY CALIBRATIONS; PRESSURE MEASURED IN TERMS OF DISTANCE TO CALIBRATION PEAKS.

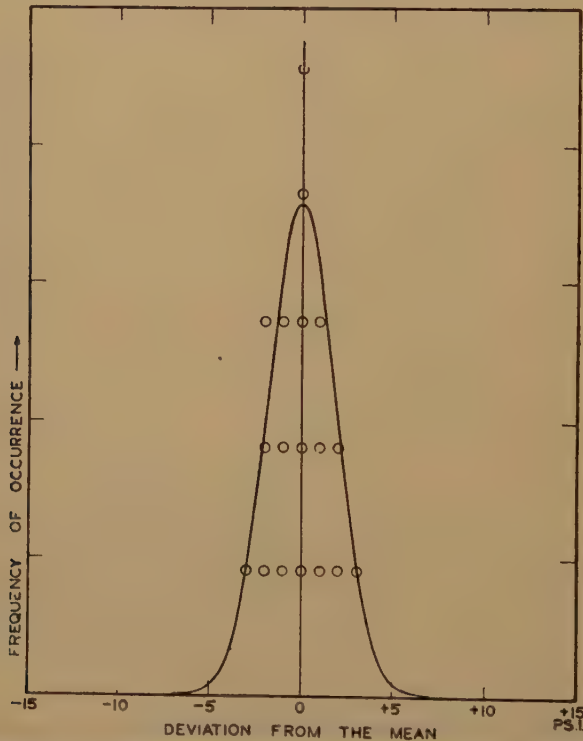


FIG. 9.—DISTRIBUTION OF GAUGE ERRORS; PRESSURE MEASURED IN TERMS OF DISTANCE TO CALIBRATION PEAKS.

can be lined up on the two calibration plateaus and the displacement between them and the bottom-hole pressure deflection can be read.

of the pressures obtained with this method and also on the basis of the pressure when calculated to the zero line. In general, it was found that the differential readings on

the charts were somewhat more reproducible than the deflections would have been if referred to the zero line. However, the main advantage of the procedure lies in

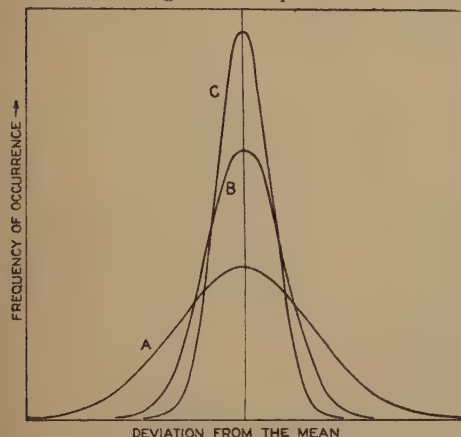


FIG. 10.—COMPARISON OF DISTRIBUTION OF GAUGE ERRORS.

Curve A, using base line.

Curve B, using zero line.

Curve C, using calibration peaks.

the fact that the calibrations are on the identical charts for which they are used. Laboratory tests have shown that duplicate pressures are more reproducible when made on the same chart than when made on different charts. Thus this method of putting the pressure and the calibration on the same chart improves the accuracy. Fig. 9 shows the available data plotted so that the area under the curve is the same as the previous figures. The 90 per cent error in this case is 3 lb. per sq. in., compared with 5 for use of the zero line and 8 for the base line (although, since the number of data shown is smaller, this result will bear further confirmation).

The data on this method are tabulated in Table 2. In measurements at field No. 4, where the well pressure was 5700 lb. per sq. in. and a 6000-lb. per sq. in. gauge had to be used, the gauge itself was affected somewhat by the high pressures and was changing with time during the survey. Thus the reproducibility of this survey was poorer than that of the other

surveys. For this reason data on this survey—and those marked with a single asterisk (taken on a gauge not showing good calibration reproducibility) in field 2

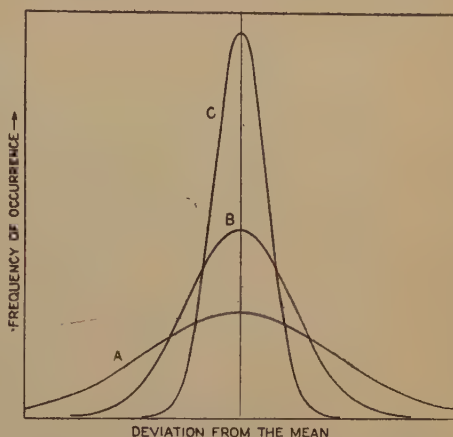


FIG. 11.—COMPARISON OF DISTRIBUTION OF GAUGE ERRORS INCLUDING CALIBRATION ERRORS.

Curve A, using base line.

Curve B, using zero line.

Curve C, using calibration peaks.

were not included in Fig. 9. The results shown for fields 1, 2 and 4 are more nearly representative of what can be accomplished using the new procedure. The accuracy of these surveys is all the more remarkable when it is remembered that these values already contain calibration errors.

Fig. 10, on which the curves from Figs. 6, 7 and 9 are superimposed, gives a direct comparison of the statistical error distribution using, respectively, (1) pressure readings from the base line with separate calibration, (2) pressure reading from the zero line using separate calibration, and (3) pressure compared with calibration on the same chart (in order of increasing peak height). However, in the first two cases, the chart readings must be compared with calibrations based on readings taken from other charts, and since the errors in the calibrations are similar to those of the pressure charts, the errors shown for the first two cases should be multiplied by $\sqrt{2}$ in order to be comparable to the third

case, which obviates most of this added error by placing the calibrations on the bottom-hole pressure chart. This gives the comparison shown in Fig. 11, the 90 per

sq. in., these errors expressed as percentage of the measured pressure would be 0.3, 0.2 and 0.08 per cent. The gauge had a full-scale reading of 6300 lb. per sq. inch.

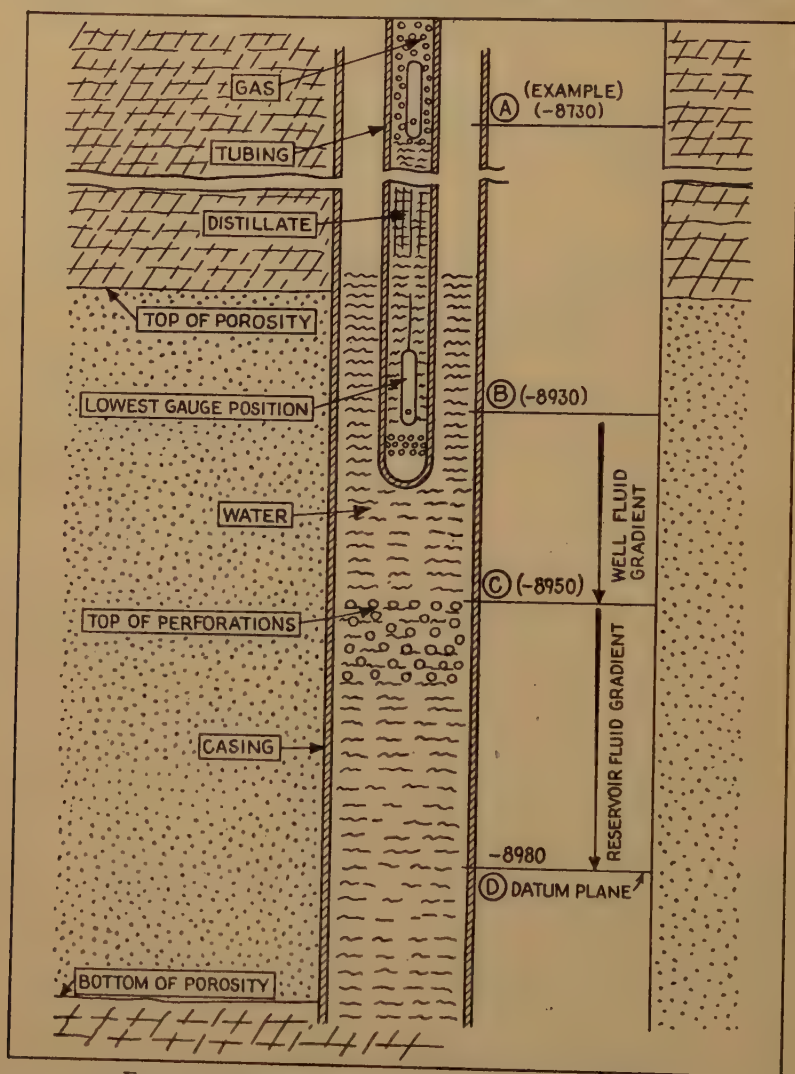


FIG. 12.—METHOD OF MAKING PRESSURE CORRECTIONS.

From gauge position to top of perforations on basis of well-pressure gradient, and from top of perforations to datum level on basis of hydrostatic gradient in reservoir.

cent error being 11, 7 and 3 lb. per sq. in. for base line, zero line and field calibrations, respectively.

Since these tests were for the most part made in the range from 3500 to 3800 lb. per

Doubtless this procedure is not one that should be used in all pressure surveys, for in many cases the accuracy desired is not great enough to justify the additional time required. Generally, if the gauge is to be

left in the calibrating bath and in the well long enough to reach temperature and pressure equilibrium, each well test requires from 2 to 3 hr. However, where precise data are needed this time has been found to be well justified. (It should not be forgotten that these field calibrations eliminate the time otherwise required for laboratory calibrations.)

The data on field No. 3, Table 2, illustrate how this improved accuracy of the bottom-hole pressure measurements can greatly extend the usefulness of bottom-hole pressure surveys. Previous to August there were no pressure data on field No. 3. However, leasing and completion work made it imperative to obtain the best possible reserve estimates. Inasmuch as the seismic surveys had not been completed, the only possible method of estimating the reserves was by use of the pressure-decline data. In the first survey shown, an average pressure of 5702 was obtained. Ten days later, after 100 million cu. ft. of gas had been produced, the second survey was made. The pressure of 5672 obtained in this survey indicated a pressure decline of 30 lb. per sq. in., which, correcting for gas-law deviation, gave reserves of 37 billion cu. ft. (A super pressure of 1500 lb. above hydrostatic indicated that no water drive was present, so that the reserves could be estimated from material-balance considerations.) Keeping in mind that the pressure gauges are guaranteed to be accurate to only ± 15 lb. per sq. in., it is apparent that this pressure change of 30 lb. per sq. in. could not ordinarily have been measured with the usual field technique. In fact, since the gauge was changing its modulus during this period, the previous type of survey could not have been trusted at all.

INTERPRETATION ERRORS

In addition to the methods already cited for reducing errors in the gauge itself, there are several precautions that should

be taken in planning the survey and interpreting the results, since, as mentioned before, we are generally interested in the pressure out in the reservoir rather than the pressure at the bottom of the well.

Fluid Heads.—It is common practice to correct pressures from the level reached by the gauge to some datum level used for the entire reservoir. This is done by use of the pressure gradient in the well, which usually is measured by stopping the gauge at several points in the course of reaching bottom. Since the "datum level" usually is taken close to the mean level of the reservoir fluid, and since the gauge frequently is stopped some distance above this, errors of as much as 10 to 15 lb. may be caused by failure to know what fluid is in the well below the gauge. Furthermore, if the datum level is not close to the perforation level, the correction indicated, which gives the pressure in the well at the datum level, may be substantially different from the pressure that exists in the reservoir at datum level—particularly in distillate wells. Since outward flow of lighter reservoir fluids would be expected to be easier than flow of the heavier well fluids into the reservoir, it may be expected that pressure equilibrium occurs between the well and the reservoir at the top of the perforations. The well gradient, therefore, is used to correct from the lowest gauge position to the top of the perforations, and the reservoir gradient from the top of the perforations to the datum level in the reservoir (Fig. 12). To reduce uncertainties in these corrections, well completions should be made with a view to allowing pressures to be taken opposite the top of the perforated section.

Pressure Gradients.—Finally, bottom-hole pressures may differ from mean reservoir pressures because of pressure gradients around the wells. This difficulty ordinarily is met by shutting in the wells a specified length of time before making tests. In fields containing fluid of low

viscosity, such as distillate, if the permeability is high a 24-hr. shut-in period may be ample to ensure pressure equilibrium to within 1 or 2 lb. throughout the reservoir. However, in some wells this may be an entirely inadequate solution of the problem, as indicated by one of Atlantic's fields where the standard 24-hr. shut-in pressures are as much as several hundred pounds below the field pressure. Obviously, in such a field it would be pointless to use a high precision technique for routine pressure measurements. But when extended build-up curves are run in order to estimate the discrepancy between routine bottom-hole pressures and actual field pressures, precise measurements may be of considerable value in showing the exact pressure changes when the build-up rate is slow: these changes having considerable effect on the extrapolation to estimated field pressures. A clear understanding of the pressure distribution in such a field must depend, of course, not only on bottom-hole pressure measurements but upon a complete reservoir analysis, taking into consideration all available data on geological factors, production of gas and water as well as oil, productivity indexes, core analyses, and any other available information.

DISCUSSION

(Warren J. Jackson *presiding*)

C. H. PISHNY.*—Dr. Brownscombe's paper is of real value. The industry has long needed information on the degree of accuracy as well as the variations that may be expected from subsurface pressure gauges.

It might be interesting to review some of the development in the past 15 years or so on one type of gauge. The first charts were pen and ink and were unsatisfactory. The brass stylus on sensitized paper followed and is still used. It was found, however, that the chart, unless cut to extreme accuracy might slip in the chart carrier and most operators glued the chart into the holder. Temperature change and moisture also caused variations in the paper. The brass

stylus would wear and, since it was difficult to sharpen properly, the tendency was toward wide lines on the chart. The most accurate chart thus far in general use is the sensitized metal chart with steel stylus or gold-pointed stylus.

I have never ceased to marvel that a gauge of $1\frac{1}{4}$ in. outside diameter can actually be a precision instrument. In the earlier stages of development the difficulties were so numerous that the accuracy now possible seemed quite unattainable for common practice.

E. R. BROWNSCOMBE (author's reply).—The stylus we used was a hard metal point on a chart that had a carbon black surface. The advantage of the hard point is that it does not need sharpening.

I would like to say again that the manufacturers are putting out a very good product, and have done it with all the restrictions on use of metals they have had to face in the past few years.

LEE FLOOD.*—I rather expected that you would dwell more on the relative importance of shut-in time prior to making the bottom-hole pressure test. Have you reached any conclusions as to the variation in shut-in time on different wells in getting comparable results; and as most wells do have different build-up characteristics, how would it be best to standardize on shut-in time prior to the test?

E. R. BROWNSCOMBE.—Undoubtedly it would be well to standardize on a shut-in time for each well. What that time would be and whether it would be the same for all the wells would depend on a reservoir analysis, keeping in mind the purpose of the pressure tests and the build-up characteristics of each well. I do not believe that offhand it is possible to state any time that will be satisfactory all around.

C. L. RABE.†—What technique is being used in reading the black-face chart? How do you see that line?

E. R. BROWNSCOMBE.—The operator has the base line magnified. The lines on the black chart are shiny lines on a dull black surface. When

*Goldsmith Pool Engineering Committee, Midland, Michigan.

†Shell Oil Company, Inc., Midland, Michigan.

* Consulting Engineer, Fort Worth, Texas.

the stylus moves on it the black material is polished; in effect, there is a bunch of little mirrors. On the first slide we showed the microscope was tilted to give specular reflection so that the line showed up as a very bright image. Since then we have had a microscope built especially for this purpose, with a vertical illuminator.

A. J. ABRAMS.*—If you read it with a microscope, do you have some technique for magnifying? I take it you can take off those plateaus.

E. R. BROWNSCOMBE.—Apparently you are talking about enlarging a photographic image. That would introduce other errors. The photographic paper we have tends to shrink and swell. After the chart was magnified it would be necessary to measure off the distances by some other means, and I don't think that the work involved would be appreciably reduced.

WILLIAM HURST.†—Do you have any trouble with getting accurate base lines?

E. R. BROWNSCOMBE.—Yes, we do have trouble with that. It depends to a large extent on the condition of the particular gauge. Some gauges draw a more accurate base line than others. That is also the reason we like to put a zero pressure line on before and after pressure measurements; thus getting a theoretical, but at least a straight, base line along the bottom. When you use field pressure-measurement technique, you can compare the two and do not have to use base lines whether straight or not. If the pressure plateau is not straight, that is a different matter.

LEE FLOOD.—What is the relative error in using one of the little inexpensive scanners? The one I am talking of is made in California and costs about \$15.

E. R. BROWNSCOMBE.—I believe the main source of error would be in the measuring end. What sort of scale is on it, and how close can you read it?

J. A. CLAY, JR.‡—It more or less slides on a scale and you look right at the center of the target—through a magnifying glass. We have had three people read the same chart and come out within one thousandth of an inch.

E. R. BROWNSCOMBE.—But the microscope reads it to ten thousandths. On these measuring charts a small distance is covered and it must be read very accurately. Also, although you can check within one thousandth of an inch, you will occasionally find that you will be more than two or three thousandths off. My inclination would be to get a better instrument, if other factors in the measuring technique warrant it.

LEE FLOOD.—Several in the room, I gather, have used this little scanner, and I hear they have been fairly well satisfied with it, without going to so much expense. How much does this microscope cost—isn't it about \$200? Do you use the scanner with the metal chart?

E. R. BROWNSCOMBE.—With the Humble bomb, I do not think you would be justified in using it, as that gauge records on paper. It would not be possible to read to ten thousandths of an inch on a paper chart, and since the Humble instrument gives a larger displacement it is not necessary to read its charts with such precision.

J. A. CLAY, JR.—I have had only a little experience with it. I notice on your calibration that this is subject to bottom pressure. On this new type of pressure equipment we always take a calibration going up as well as down, as we found a slight lag in the tubing in adjusting to the new pressure. What type of calibration did you make on those with only one point pressure, or did you make allowances for the pressure errors? Did you take pressure in the well before leaving it?

E. R. BROWNSCOMBE.—In calibration for the field we used only one point at the estimated pressure in the bottom of each well, directly comparing that point with the pressure in the bottom of the well. On the way up and on the way down there is a difference in the reading. You go up one path and down a different one. However, the top point in each is the same. I do not believe the lag is involved in our technique.

J. A. CLAY, JR.—If someone reading the point missed it, you would have to go back to it. You would have to take another calibration.

* Magnolia Petroleum Co., Dallas, Texas.

† Shell Oil Company, Inc., Houston, Texas.

‡ Service Engineers, Inc., Fort Worth, Texas.

E. R. BROWNSCOMBE.—That is true, unless you corrected back up the well on the basis of the well fluid gravity.

J. A. CLAY, JR.—Often the tubing is very close to the bottom of the well, and if you are going to do reservoir work you want the pressures as close to the reservoir depth as you can, and want it identified. If you calibrate the bomb on increasing pressure, you get a certain point and different measurements for the same pressure with decreasing pressures. A small lag in the adjustment of the bourdon tube can cause this.

E. R. BROWNSCOMBE.—It is true that you cannot make your calibration on an increasing pressure and then use it on a decreasing pressure. Relative to stopping at the reservoir depth, it should be noted that the pressure in the tubing at this depth is not necessarily the same as the pressure in the reservoir at this depth. As pointed out in the discussion and in Fig. 12, in a perforated well the gauge should be at the bottom of the tubing, which should

be opposite the perforations. In this case, correction to the pressure at the desired datum level is then made on the basis of the gravitational heads in the reservoirs. Any other arrangement requires corrections for fluid heads in the well in addition to those in the reservoir.

CHARLES PATTON.*—In speaking of these errors—would they use the isostatic law in making the bourdon tubes?

E. R. BROWNSCOMBE.—I am not familiar with that.

C. H. PISHNY.—A great deal of experimentation was done in the construction of the finished bourdon type pressure element. Tubes made of various different alloys and materials were made into pressure elements and tested. It is probable that over the years practically any material or process that might make a better element has been tried.

* Magnolia Petroleum Co., Dallas, Texas.

Method for Determining Minimum Waiting-on-cement Time

By R. FLOYD FARRIS*

(Tulsa and Houston Meetings, October 1945)

ABSTRACT

A METHOD is presented for determining minimum waiting-on-cement time, which takes into account the differences that exist between types and brands of cements and such individual well conditions as depth, temperature, and pressure.

The basis for the method was determined by laboratory tests. Being a laboratory development, several steps were required to prove its merit. The first step consisted of laboratory tests designed to determine the minimum cement strength required in wells. Basis was found for setting a minimum value of 8 lb. per sq. in. tensile strength. Next, it was shown by laboratory tests that the time to 8 lb. per sq. in. tensile strength may be expressed as a function of consistometer stirring time to 100 "poises," the approximate relation being "the time to 8 lb. per sq. in. tensile strength equals the time to 100 'poises' times three." Next, it was shown that the time of maximum temperature development in cement slurries, due to heat of hydration, is also related to consistometer stirring time to 100 poises, but only by a factor of approximately two. It was shown also that the shut-in casing pressure will build up after cement is placed and register a maximum pressure at approximately the same time the slurry down the hole attains maximum temperature. From this and the relationships listed above, the general rule was established that minimum waiting-on-cement time (time to 8 lb. per sq. in.) after casing cement jobs in any well is equal to the time when the shut-in casing pressure reaches a maximum, as measured from the initial mixing of cement, times a factor of 1.5.

Cement plugs drilled in the field at the time

prescribed by this formula were found to drill "firm to hard," thus confirming the laboratory tests.

These tests prove that many of the present regulations for waiting on cement require a longer time than is absolutely necessary. Use of the method herein proposed offers the possibility of a saving of \$1200 per well.

INTRODUCTION

The length of time allowed for cement to set after casing is determined either by state-wide rules, field rules, or self-imposed rules written into drilling contracts. In general, the time is dictated by experience and common practice. However, owing to differences in opinion and in experience of the various groups involved, waiting-on-cement time often varies from one area to the next. For example, an operator in an area where no rules exist may drill out of surface pipe at 24 to 36 hr., while another operator in another area may wait 48 hr. or more to comply with state or field rules, although the depth of the well, hole size, type of cement, and other data are identical. An even greater difference in practices will be found by making similar comparisons with respect to oil-string cement jobs. Differences in waiting-on-cement times of 36 to 48 hr. are common.

Further complicating the picture is the rather common practice of allowing more waiting time for cement to set at the greater depths than is allowed at the shallow depths. This practice has existed for years in spite of the common knowledge^{1,2,3} that the temperature of the earth at the usual setting depths of surface

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* Stanolind Oil and Gas Co., Tulsa, Oklahoma.

¹ References are at the end of the paper.

casing is much less than that at the depths at which oil strings are set, and that increased temperature greatly accelerates the rate of setting and hardening of cement.

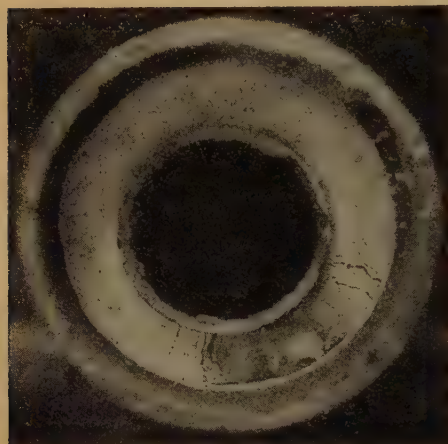


FIG. 1.—CEMENT IN ANNULUS.

End view of 5 1/2-in. o.d. casing inside 9 5/8-in. o.d. casing.

The foregoing thoughts suggest lack of a fundamental basis for determining waiting-on-cement time.

The minimum strength cement must develop in a well before it will secure pipe in the hole, exclude undesirable well fluids, and withstand the shock of drilling, and how long cement must stand before it attains that minimum strength, are questions often discussed but never completely answered. The industry has operated to the present time without the answers to these questions, simply by allowing long waiting periods for the cement to set. Thus, since experience has taught that waiting periods ranging from 36 to 72 hr. would give satisfactory results, these periods have become standard practice in many areas; however, it is easy to understand how a practice derived in this manner might include more time than is absolutely necessary.

Experiments conducted in the Stanolind Oil and Gas Co. Research Laboratory sug-

gested that cement in wells may set and gain adequate strength in much less time than normally is allowed for that purpose. This finding led to the development of a simple method for determining the mini-

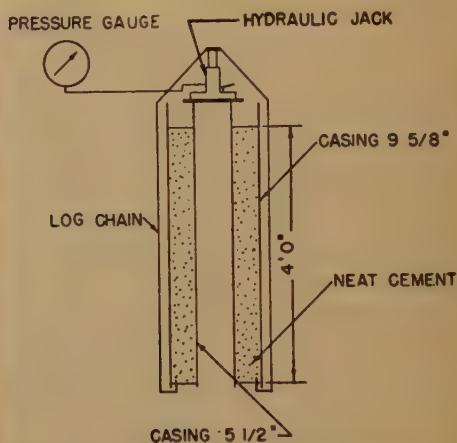


FIG. 2.—APPARATUS FOR MEASURING BONDING STRENGTH OF CEMENT IN ANNULUS.

mum waiting-on-cement time, which will apply to any well condition. The purpose of this paper is to describe the laboratory and field tests that contributed to the development of this method.

BASIS OF METHOD

The expression "waiting-on-cement time," hereinafter referred to as WOC time, simply means the time spent in waiting for the cement to set and gain a given minimum strength. Thus, any logical system for determining WOC time must be based on minimum requirements for cement strength used in wells. Once this has been established, the time to that strength can be reasonably accurately determined.

To obtain information as to what strength cement should develop in wells before it is drilled out, laboratory tests were conducted in which a correlation was made between cement tensile strength and the bonding strength of cement in an annulus. The apparatus consisted of seven

pieces of 9½-in. o.d. pipe 5 ft. long, into which were centered similar lengths of 5½-in. o.d. pipe. Standard portland cement slurry weighing 15.6 lb. per gal. was poured into the annulus of each unit to a height of 4 ft. Some of the same slurry was placed in briquette molds for tensile-strength tests; also, cement slurry was placed in Vicat molds for determination of initial and final set. The cement was cured at atmospheric temperature, approximately 90°F. An end view of the cement in the annulus between the two sizes of pipe is shown in Fig. 1.

The bonding strength of the cement in the annulus was determined by measuring the force that must be applied to the 5½-in. pipe to break the cement bond and move it with respect to the outside (9½-in.) pipe. The means of doing this is illustrated by Fig. 2. Each time the bonding strength of cement in the annulus was tested, observations were made of the corresponding cement strength and the progress toward the initial and final set. Table 1 presents a summary of the test results.

TABLE 1.—*Cement Bonding Strength*

Cement Age, Hr.	Force to Break Bond of 4 Ft. of Cement, Lb.	Cement Tensile Strength, Lb. per Sq. In.	Remarks
1.83	400	0	Soft cement slurry
2.33	550	0	Soft cement slurry
3.08	1,300	0	Initial set
3.66	4,000	4 est.	Cement stiffening rapidly
4.42	18,200	8 est.	Final set
5.50	20,000+	12	Could not break bond
6.50	20,000+	20	Could not break bond

The rate of increase in cement bonding strength is better demonstrated when these data are plotted on a graph. Fig. 3 shows that cement has an enormous bonding strength at its final set.

Table 2 shows the calculated load each foot of cement in an annulus will support at various cement strengths, together with the length of various pipes of equivalent weight.

Returning to the question of how much strength cement should develop in a well before it is drilled out, one can reason that it would not be safe to drill out cement before it reaches the initial set, even though the data in Table 2 indicate that the slurry may support the pipe, because it is not until after the initial set that the slurry passes from the fluid state into that of a solid. In fact, solidification of cement may not be called complete until it has reached the final set. Therefore, since drilling inside of casing before the cement on the outside reaches its final set could possibly reduce it to the fluid or semifluid state, it is obvious that cement should not be drilled out before it reaches the final set, which corresponds to a tensile strength of approximately 8 lb. per sq. inch.

TABLE 2.—*Strength of Cement*

Cement Age, Hr.	Force to Break 1 Ft. Cement Bond, Lb.	Cement Tensile Strength, Lb. per Sq. In.	Length of Pipe 1 Ft. of Cement Will Support, Ft.		
			5½ In., 17 Lb.	7 In., 24 Lb.	13½ In., 72 Lb.
1.83	100	0	5.8	4.1	1.3
2.33	137	0	8.0	5.7	1.9
3.08	325	0 (initial set)	19.1	13.5	4.5
3.66	1,000	4 est.	58.8	41.6	13.8
4.42	4,550	8 est. (final set)	267.5	189.6	63.1
5.50	5,000+	12			
6.50	5,000+	20			

If cement should not be drilled out before it attains a tensile strength of 8 lb. per sq. in., the next question is: Would it be safe to drill it out at a tensile strength of 8 lb. per sq. in.? The foregoing data strongly suggest that it would be safe to drill out cement at that strength. At a strength of 8 lb. per sq. in., for example, Table 2 indicates that each foot of cement in the annulus should support 267 ft. of 5½-in. o.d. 17-lb. pipe, and Fig. 3 shows that the rate of bonding-strength development is extremely rapid at that point and probably reaches even greater proportions shortly after that time. These considera-

tions, together with the general feeling that "green" cement may be drilled with less damage to the cement in the annulus, and in view of the fact that the full weight

govern the time required for it to stiffen to a given consistency, reach a final set or attain a given strength, will be water-cement ratio, temperature, and pressure.

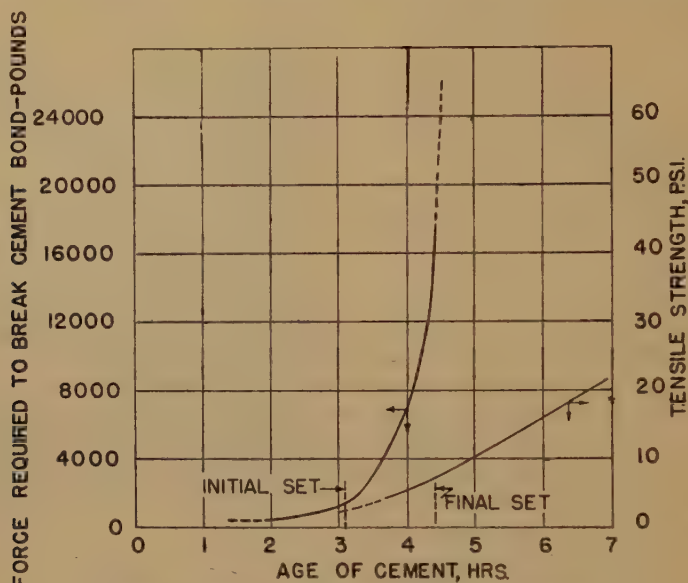


FIG. 3.—DEVELOPMENT OF BONDING STRENGTH.

of casing is apt to be set down on cement only when the casing is cemented to the surface, prompted the tentative conclusion that the minimum cement-strength requirement before the plug is drilled out is approximately 8 lb. per sq. inch.

PREDICTION OF CEMENT-STRENGTH DEVELOPMENT IN WELLS

First Method

Having determined by laboratory tests what appears to be the minimum strength requirement of cement in wells, the next step is to develop a method of determining when cement in wells will attain that strength. Cement slurry, whether in a well or a laboratory apparatus, will remain fluid for a time after the slurry is formed, then it will stiffen, set, and start to develop strength. Also, regardless of whether or not the slurry is in a well or in a laboratory apparatus, the factors that will largely

When well conditions or laboratory conditions accelerate the stiffening time of cement to a given consistency, the time to the initial set will be decreased correspondingly. Since both times are affected by the same factors, it appears that it should be possible to express one as a function of the other. If the time for cement stiffening to a given consistency is related to the time of final set (8 lb. per sq. in. tensile strength), and if laboratory tests could be conducted to predict the actual time of stiffening of cement in wells, it would be possible to predict with approximately the same accuracy the time when cement in wells reaches the final set, or a strength of 8 lb. per sq. inch.

In 1941, Stanolind Oil and Gas Co. developed a method¹ of testing cements in which temperatures and pressures are varied to correspond with the increasing temperatures and pressures imposed upon cement slurries as they are pumped from

surface to bottom-hole conditions of wells of various depths. The results obtained from these tests are called cement stirring-time tests to 100 poises at simulated well depths. Field tests have shown that this method of evaluating cements describes reasonably accurately the actual performance of cement slurries in wells. Table 3 is a tabulation of cement stirring-time tests to 100 poises at various simulated well depths, the time to 8 lb. per sq. in. tensile strength (assumed to be equivalent to the time of final set), and the ratio of these times.

TABLE 3.—*Cement Stirring-time Tests*

Type of Cement	Well Depth Simulated, Ft.	Stirring Time to 100 Poises, Hr.	Time to 8 Lb. per Sq. In. Tensile Strength, Hr.	Time to 8 Lb. per Sq. In.
				Time to 100 Poises
Standard Portland.	2,000	3.5	5.4	1.54
	4,000	3.0	3.8	1.27
	6,000	2.5	2.9	1.16
Slow-set A.	8,000	4.0	8.5	2.12
	10,000	3.4	8.0	2.35
	12,000	3.0	7.9	2.63
Slow-set B.	6,000	3.7	10.6	2.86
	8,000	3.1	9.3	3.0
	10,000	2.5	7.5	3.0
Slow-set C.	6,000	4.0	10.1	2.52
	8,000	3.1	8.8	2.84
	10,000	2.6	7.8	3.00
Slow-set D.	6,000	3.7	6.5	1.75
	8,000	3.3	5.2	1.57
	10,000	4.4	5.4	1.23

Data in the fourth column of Table 3 were obtained from time-versus-strength data by extrapolation from actual test points in the neighborhood of 20 to 30 lb. per sq. in. tensile strength. For that reason, and also because the strength tests were made at atmospheric pressure, the data under this heading do not exactly describe the time to 8 lb. per sq. in. tensile strength in a well. The times are a little longer than would be found in actual practice, and thus become an added safety factor to the method herein proposed. But, in spite of the fact that the test data in Table 3 are not perfectly representative, the ratio of the time to 8 lb. per sq. in. strength to the time to 100 poises is surprisingly

constant. The average ratio multiplied by the time to 100 poises would quite accurately predict when cement in the average well attains a strength of 8 lb. per sq. in. However, since it is desirable that cement in all wells, not just in the average well, reach a strength of 8 lb. per sq. in. before it is drilled out, the largest ratio, 3, must be used. In general, therefore, cement in wells will attain a tensile strength of at least 8 lb. per sq. in., the minimum strength requirement in wells, at a time corresponding to three times the time required for the cement to reach a consistency of 100 poises at well conditions of temperature and pressure. Or, for practical purposes,

$$\begin{aligned} \text{Minimum WOC time} &= T_{8 \text{ lb. per sq. in.}} \\ &= T_{100 \text{ poises}} \times 3 \end{aligned}$$

Where:

$$T_{8 \text{ lb. per sq. in.}} = \text{time to a tensile strength of 8 lb. per sq. in.}$$

$$T_{100 \text{ poises}} \times 3 = \text{well simulation stirring-time tests to consistency of 100 poises.}$$

It will be shown later that this method of predicting development of cement strength in wells is actually more accurate than may be believed at this point. However, since the method involves several assumptions, thought was turned to the development of a simpler, more accurate method of determining strength development in wells.

Second Method

When water is added to dry cement, chemical reactions occur that give off heat. It is this behavior of cement slurry that permits one to run a recording temperature instrument into a well after a casing cement job and find the location of the top of the cement behind the pipe. It has been found that the temperature of cement behind casing may remain higher than the temperature of the adjacent formation for as long as 60 to 70 hr. after pumping the cement into the well. Field tests have

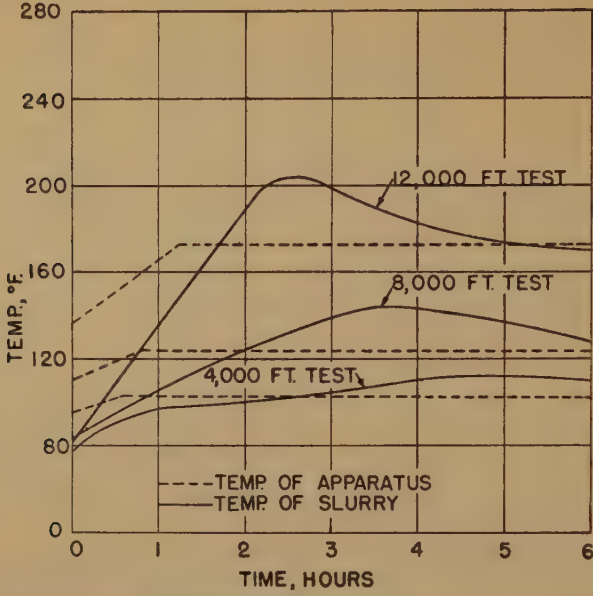


FIG. 4.—TEMPERATURE DEVELOPMENT IN STANDARD PORTLAND CEMENT SLURRY.

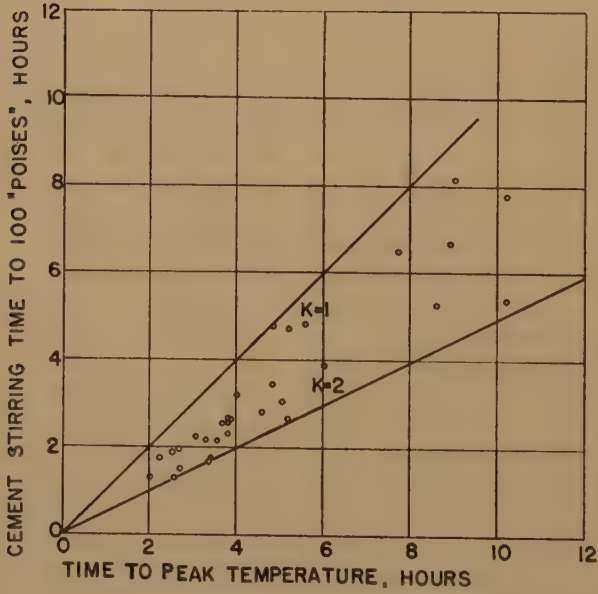


FIG. 5.—STIRRING TIMES OF CEMENTS.

shown also that temperature surveys made at 24 hr. or less after cementing show the tops of cement more distinctly, suggesting that some time after cement is placed

on standard portland and slow-set cements, to throw some light on this subject.

A plot of the stirring time of various cements at various conditions of tempera-

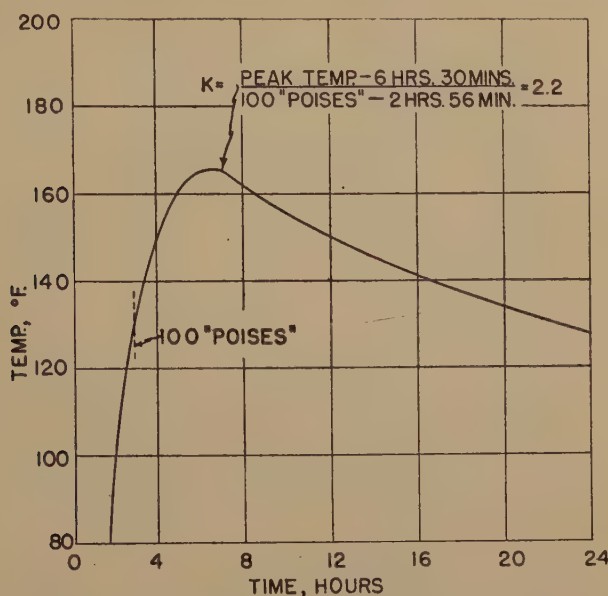


FIG. 6.—PEAK TEMPERATURE IN RELATION TO STIRRING TIME.

in a well the temperature increases to some maximum value above the surrounding strata, then slowly decreases to the normal temperature at that depth. Laboratory tests were made to determine the time of maximum or peak temperature of cement slurries at various pressures and temperatures is simulation of various well depths.

An example of maximum temperature development in a standard portland cement slurry at three stimulated well depths is shown in Fig. 4, which shows that the greater the depth, the more quickly the cement reaches the maximum temperature. Viewing this behavior brings to mind the fact that the greater the depth, the more quickly cement stiffens and sets. That thought, in turn, suggests that the time to maximum temperature development in a well may be related to stirring time to 100 poises. A number of tests were made

and pressure, corresponding to wells of various depths, versus the time to the peak or maximum temperature development (Fig. 5) suggests that these factors may be reasonably closely related to each other. In other words, knowing the stirring time to 100 poises, one can multiply that time by a factor (K), which is more than one but less than two, and predict the approximate time when cement in wells will reach the peak temperature. Fig. 5 indicates that the average K factor is somewhere between 1.5 and 2.0.

Field tests were then made to determine when cements in wells actually reach peak temperature and to determine how it is related to laboratory tests of stirring time to 100 poises. The first test was run in a well in North Cowden field, Ector County, Texas, where 5½-in. o.d. casing was set at 4624 ft. and cemented with 125 sacks of a standard portland cement.

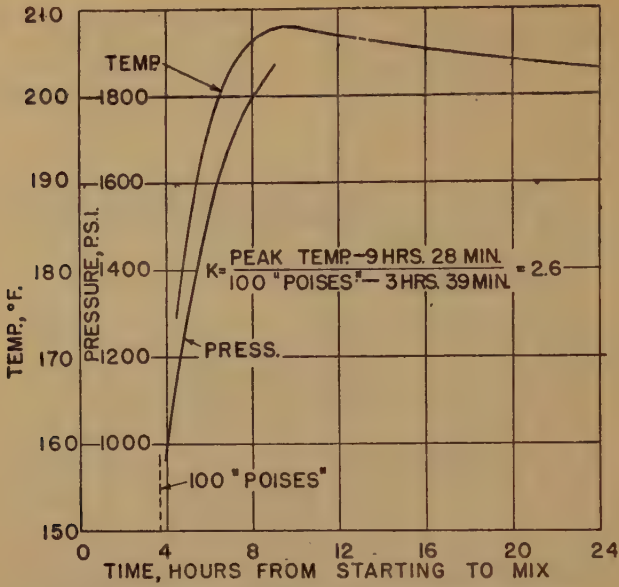


FIG. 7.—RELATION OF PRESSURE AND TEMPERATURE.

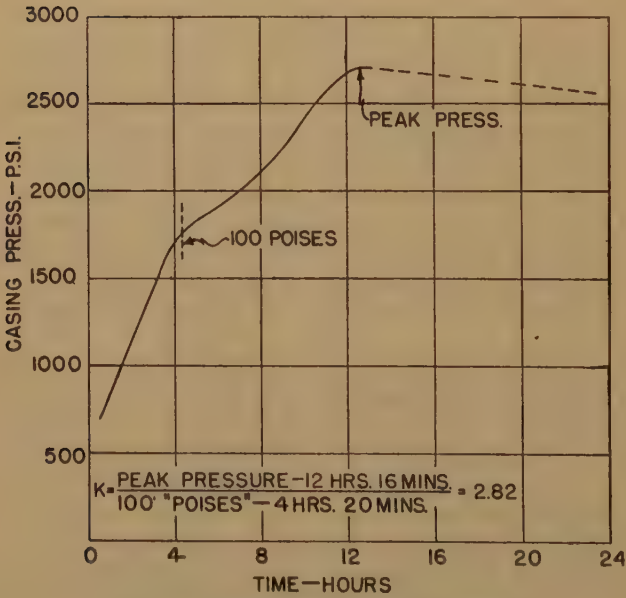


FIG. 8.—PRESSURE BUILD-UP ON CASING.

Immediately after the cement was pumped down, a recording temperature element was lowered into the casing to a point well below the estimated top of the cement and was left at that point for approximately 24 hr. The temperature recorded during that time is plotted on Fig. 6. The ratio of the time to the peak temperature in this well to the stirring time to 100 poises, as determined by a laboratory well-simulation test on the same cement, is 2.2, or slightly higher than the K factor indicated by previous laboratory tests.

Since the maximum temperature recorded in this well was so very much greater than the normal static formation temperature, approximately 94°F., at that depth, the thought occurred that perhaps if the casing being cemented is closed in after the cement is pumped down, expansion of the fluid in the casing should cause an increase in the shut-in casing pressure, which would reach a maximum at approximately the same time that the cement down the hole reaches its maximum temperature. This thought was investigated in the next field test.

In the next field tests, the test procedure used on the previous well was followed, except that hourly readings of the shut-in casing pressure were taken. This well was drilled in Tri-Cities field, Texas, where 5½-in. o.d. casing was set at 7681 ft. and cemented with 600 sacks of a slow-set cement. Fig. 7 shows the results of these tests. The pressure built up with temperature to approximately the peak, but, unfortunately, the pressure on the casing was bled off at that time. Ratio of the time to peak temperature to the time to 100 poises was found to be 2.6.

Another test was run in Tri-Cities field to obtain a record of the pressure build-up on the casing, since readings were not taken to the maximum pressure on the previous well. In this test, 5½-in. o.d. casing was set at 7612 ft. and was cemented with the same type and amount of cement. The results

(Fig. 8) confirmed the thought that pressure on the casing after cement is placed reflects heat of hydration of cement in a well. The ratio of time to peak pressure to stirring time to 100 poises was 2.82 in this case. Why the peak temperature occurred in one well at 9 hr. and 28 min. and the peak pressure occurred at 12 hr. and 16 min. in another well of approximately the same depth is understandable in view of the fact that the cement showed different setting-time characteristics, although the same brand was used in both cases. Also, another possible difference between these wells is the fact that the latter was cemented during a season of the year when the atmospheric temperature was probably less than that at the time of cementing the first well. It is a well-known fact that mud-pit temperatures are affected by atmospheric temperature, which, in turn, affect the bottom-hole temperatures and, therefore, the setting time of cement placed therein.

A pressure build-up test was made on a well in West Edmond field, Oklahoma, where 7-in. o.d. casing was set at 7028 ft. and cemented with 700 sacks of a special experimental oil-well cement. Fig. 9 shows that the ratio of peak pressure to 100 poises was 2.4.

Surface pipe, 10¾ in., was set at 649 ft. in a well in Sour Lake field, Texas, and cemented to the surface with 500 sacks of a standard portland cement. Fig. 10 shows that the ratio of peak pressure to 100 poises was 2.1. Pressure was bled down once, to permit installation of a recording pressure gauge. Pressure was bled down at first to avoid subsequent high pressure on the casing. When the peak pressure was reached, a transit was set up some distance from the well and trained to a mark on the pipe to observe any settling of the pipe when the strain was released. The weight of the pipe was set down on the cement, but no movement was observed.

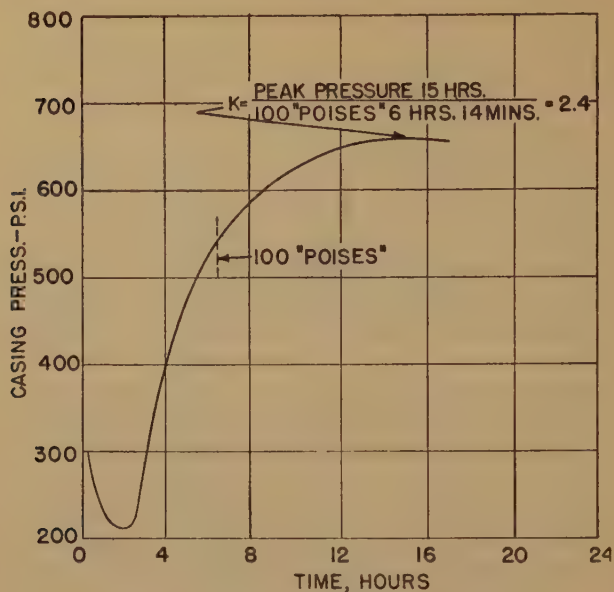


FIG. 9.—PRESSURE BUILD-UP ON CASING.

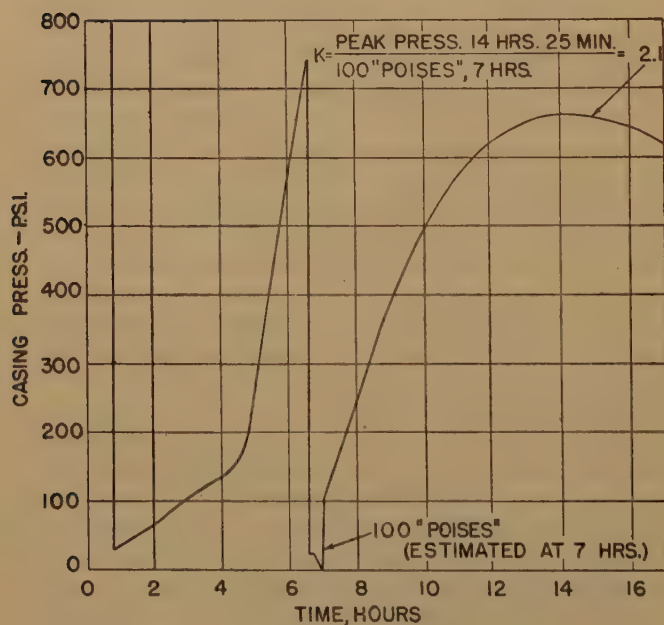


FIG. 10.—PRESSURE BUILD-UP ON CASING.

Earlier in the discussion it was shown by laboratory tests that the ratio of the time to maximum temperature development in cement to the stirring time to 100 poises is equal to a factor (K) slightly less than 2 but more than 1.5. All field tests show that the ratio is slightly more than 2 but less than 3. Since the difference between laboratory tests and field tests is small, one might strike a compromise with the statement or conclusion that cements in wells reach peak or maximum temperatures at a time corresponding to approximately twice the time required for the cement to attain a consistency of 100 poises, under the particular laboratory consistometer test conditions used in this case. This relationship, with others pointed to throughout the discussion, may be written as equations as follows:

$$T_{8 \text{ lb. per sq. in.}} = T_{\text{min. WOC}} \quad [1]$$

$$T_{\text{min. WOC}} = T_{100 \text{ poises}} \times 3 \quad [2]$$

$$T_{\text{max. temp.}} = T_{\text{max. csg. press.}} \quad [3]$$

$$T_{\text{max. csg. press.}} = T_{100 \text{ poises}} \times 2 \quad [4]$$

Therefore,

$$T_{\text{min. WOC}} = T_{\text{max. csg. press.}} \times 1.5 \quad [5]$$

where:

$T_{8 \text{ lb. per sq. in.}}$ = time from mixing of the cement to a tensile strength of 8 lb. per sq. in.

$T_{\text{min. WOC}}$ = minimum waiting-on-cement time.

$T_{100 \text{ poises}}$ = cement well simulation stirring-time test to 100 poises (pressure consistometer; Stanolind test procedure).

$T_{\text{max. temp.}}$ = time to maximum temperature development in cement.

$T_{\text{max. csg. press.}}$ = time to maximum shut-in pressure on casing.

Eq. 5, which expresses the second method for predicting development of cement strength in wells, simply means that all one

has to do to determine the minimum WOC time in any well is to read the shut-in casing pressure after landing the cement until it reaches a maximum, then multiply the time to that point, as measured from the time of mixing the first sack of cement, by a factor of 1.5. This method is much simpler than the first method and is much more accurate, as it will reflect differences in well conditions and differences in cement behavior.

The foregoing equations describe relationships that laboratory tests indicate to be true, or approximately true, in wells with respect to minimum strength requirements and minimum WOC times. Whether or not the laboratory predictions hold true in field practice is quite another matter. Field tests were made to check the correctness of these hypotheses.

FIELD TESTS

If the trends indicated by laboratory tests are fundamentally correct, the equation for predicting minimum WOC time will apply to all portland-type cements in any well at any depth. Therefore, exceptions to field rules were obtained where necessary to permit drilling out of cement as early as might be required to check laboratory tests. Wells were selected in various areas and at various stages of drilling in order to obtain data on jobs at various depths and with different types and brands of cements. Each job differed from normal practice only in the time of drilling out of the plug. Field men were instructed to take hourly readings of the shut-in casing pressure until it reached a maximum, release pressure at that point, run the bit into the hole, and start drilling the plug at a time equal to the time to the maximum pressure times 1.5. Incidentally, field men were advised to bleed off the pressure at intervals if it reached dangerous proportions. The criterion is not necessarily the magnitude of the pressure, but, rather, is the point when the

fluids inside the casing stop expanding as a result of an increase in temperature. that releasing the pressure after it reaches the maximum is a more critical test than

TABLE 4.—WOC Field Tests

Field	Casing		Cement		Elapsed Time, Hr., to			Plug Drilled at, Hr.	Time to Maximum Casing Pressure $\times 1.5$, Hr.	Drilling Rate, Min. per Ft.	Wt. on Bit M [#] s	Rev. per Min.
	Size, In.	Depth, Ft.	Type	Sacks	Maximum Casing Pressure	Stirring Time, 100 Poises $\times 2$	Release of Casing Pressure					
Fullerton, Tex. . . .	7 $\frac{5}{8}$	3,771	Common	2,000	"	6.16	7.38	12.25	9.24 ^a	5	5	55
Fullerton, Tex. . . .	7 $\frac{5}{8}$	3,805	Common	1,800	7.25	7.23	8.0	16.0	10.87	5	2	50
Fullerton, Tex. . . .	7 $\frac{5}{8}$	3,785	Common	1,900	7.05	6.16	7.20	11.2	10.57	2.4	2	50
Fullerton, Tex. . . .	5 $\frac{1}{2}$	6,765	Slow-set	350	"	8.0	7.07	26.2	12.0 ^b	2.0	3	50
Sittner, Kans. . . .	5 $\frac{1}{2}$	3,612	Common	150	"	8.5	9.53	16.2	12.75 ^c	3	3	50
W. Edmond, Okla. . .	7	7,005	Common	700	"	5.33	6.92	"	8.0 ^c	"	"	"
Sour Lake, Tex. . . .	10 $\frac{3}{4}$	647	Common	500	14.77	14.0	14.77	24.27	22.15	0.5	6	100
Riverside, Tex. . . .	5 $\frac{1}{2}$	6,415	Slow-set	750	10.12	8.8	11.0	"	15.16	"	"	"
High Island, Tex. . .	7	5,704	Slow-set	750	15.67	11.10	15.67	"	23.5	"	"	"
Elk Basin, Wyo. . . .	7	5,300	Common	300	8.00	7.40	8.0	24.3	12.0	2.5	6	90

^a Head leaked.

^b Not drilled early.

^c T to 100 "poises" $\times 3$.

Table 4 presents a summary of eight field tests in which attempts were made to drill out cement at the minimum WOC time indicated by laboratory tests.

DISCUSSION OF RESULTS

The field tests summarized in Table 4 show by the drilling rates that the cement in each well had passed the final set, and therefore had attained a tensile strength of at least 8 lb. per sq. in. as predicted by laboratory tests. It is also interesting to note the reasonably close agreement between the time to maximum pressure on the casing and laboratory stirring time to 100 poises $\times 2$. These data show that cement tests can be made in the laboratory that will predict the approximate stiffening time of cement in wells. In three field tests, unforeseen events delayed drilling of the plug to a time that approached the usual drilling out time and thus rendered those tests practically useless as far as the subject experiment was concerned. The only information of significance obtained from those tests was that no slurry flowed back into the casing when the pressure was released. Many believe

the test of drilling the shoe. They reason that if the cement is soft it will back up into the casing when pressure is released, especially if the common type of float equipment is not used, as in two of the wells tested.

The writer is of the opinion that the tests conducted on the surface pipe cement work at Sour Lake were more severe than those at any other location. The cement was likely to have been much more "green" when it was drilled than at any other test location, owing to the low curing (formation) temperature and pressure. Immediately after the pressure was released, which, as stated before, may be a critical test of whether or not the cement has set, the master valve and blow-out preventer for 10 $\frac{3}{4}$ -in. casing were set down on the casing. The cement not only supported the full weight of the casing at that point but held the very large weight of that equipment. Next, after drilling the wooden plug and baffle collar and 4 or 5 ft. of cement, the driller stopped rotation and set all the weight of the drill pipe, kelley, and swivel (8 points) down on the cement, then increased the pump speed

to a relatively high rate to see whether the cement could be washed out. The weight indicator had picked up no weight after circulating 6 min. The driller termed the cement as drilling "firm to hard."

The cement in all the tests where the plug was drilled reasonably soon after the specified time drilled firm to hard inside the pipe and showed no evidence of flow of cement into the casing after the shoe was drilled. Also, in no case was the cement sufficiently soft to be circulated out.

These data indicate that basing WOC time on the time to maximum casing pressure times a factor is fundamentally sound and applicable to field practice. It would appear that such a system as this would be particularly attractive as a basis for State or Field rules, since the time to maximum shut-in casing pressure reflects individual conditions of the well as they affect the particular type of cement used in that well. The multiplier 1.5 merely sets the time back to allow a minimum strength to be developed. Unless further field experience proves that the multiplier 1.5 is too low, there is little reason for suggesting that a waiting period longer than that prescribed by the formula should be used. These tests indicate that seldom will rig operations permit cement to be drilled out at the minimum time. This suggests that the phrase "waiting-on-cement time" should be deleted from our vocabulary, since it has been found that the cement usually waits on the drilling crew.

Much must be done before full advantage can be taken of the indicated savings in time. Aside from the fact that certain regulations will have to be modified, certain of the routine of rigging up and handling of rig operations may have to be shifted. For example, much of the rigging up or repair around a rig that now is deferred until WOC time may be handled by extra roustabout help, or may be done by the rig crew during slack time while drilling. Also, much time is not spent in

changing rams on blowout preventers and in the installation of the master valve and the blowout preventer after setting surface pipe. If this equipment were made up in a shop ready to be flanged onto the surface pipe, it appears that it could be installed as a unit with a great deal more efficiency.

As an example of the saving that might be effected by reducing WOC time, the over-all average WOC time on Stanolind Oil and Gas Co. properties is approximately 51 hr. per casing cement job. This figure is lower than might be expected because it includes practices in areas where no regulations exist. The over-all average WOC time indicated by the method proposed in this paper is estimated to be approximately 15 hr. per casing cement job. This suggests a saving of 36 hr. per job. However, practical considerations teach that very seldom would the crew be able to start drilling on the plug so early. It has been estimated that, at least until the present rig routine is appropriately modified, the plug cannot easily be drilled out before an average time of approximately 21 hr. after cementing casing. Therefore, it appears that an average of 30 hr. per cement job might be saved without much difficulty.

Translating rig time into dollars at \$20.00 per hour, the saving should be an average of \$600 per casing cement job, or at least \$1200 per well, assuming two cement jobs per well. Realizing that more than 24,000 wells were drilled in the United States during 1944, one can appreciate how reducing WOC time might benefit the industry.

SUMMARY

It has been shown that the minimum waiting-on-cement time in wells can be reasonably accurately predicted by laboratory well-simulation tests, but can be more simply determined by observing the shut-in pressure on the casing to a maximum value then multiplying by a factor of 1.5

the time from initial mixing of cement to the time when maximum pressure is reached. Field tests show that the cement has ample strength to support the pipe and withstand the shock of drilling at that time.

A great deal of WOC time may be eliminated if regulations are relaxed and if rigging up and drilling routine is adjusted to fit in with minimum waiting-time requirements.

ACKNOWLEDGMENT

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The Wire-line Tubing Perforator and Its Use to Complete Wells for Gas Lift in the Gulf Coast Area

By JOHN O. FARMER, JR.,* MEMBER A.I.M.E.

ABSTRACT

THE wire-line tubing perforator is a mechanically operated tool that is run on an ordinary steel measuring line into the tubing of a well, under pressure, to drive into the wall of the tubing, and securely lock in place, a tapered, cylindrical insert containing an orifice. Use of the perforator obviates the necessity of pulling and rerunning the tubing to install jet collars or flow valves, reduces the cost, and simplifies the task, of placing an oil well on gas-lift operation. More important, however, is the use of the tool with a removable check valve and stop, to provide a means of washing drilling mud from the annulus between the tubing and casing, and to complete the well for gas-lift operation without exposing the producing formation to the mud column and without moving the tubing string.

This paper discusses the origin, development, and mechanics of the wire-line perforator, the various purposes for which the tool was designed, and the method of selecting orifice sizes for any depth, and gives the results obtained thus far in practical application.

ORIGIN AND DEVELOPMENT

Several years ago, a tool that could be lowered on an ordinary steel measuring line into the tubing of a well under pressure was designed and constructed for the purpose of punching a hole in the tubing walls above a shale bridge that had completely plugged the tubing of a well in the Long Lake field, East Texas. The well was in a low, swampy area, which excessive rainfall had caused to be in-

accessible by car or truck for about four months. The only equipment at the well site consisted of an ordinary steel wire line that had been carried there to measure the depth of the bridge. Since a pulling unit could not be moved to the well site, and as the pressure on the casing was 2100 lb. per sq. in., it became apparent that the only way out of the predicament was to make a perforating tool that could be lowered into the tubing on a measuring line and operated under pressure. Thus, the first wire-line tubing perforator was designed and built as an expedient, and was not used extensively until it had been redesigned to meet more frequent and increasingly urgent needs.

Until recently, it was necessary to pull the tubing to install jet collars or flow valves when a well was to be placed on gas lift. Because most companies either maintained or had access to pulling units and crews for this work, little or no thought had been given to eliminating or even simplifying this task. When the manpower and steel shortage became so acute, however, many operators suddenly found themselves without facilities to equip their wells for gas lifting. The wire-line tubing perforator already had been tried and proved successful, therefore operators immediately requested its use to punch gas-jet holes in the tubing, to eliminate the pulling and running of tubing strings.

The first deficiency revealed by more general use of the perforator lay in the inability to regulate the size of the hole punched through the tubing. The size could not be controlled to any degree of

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* Otis Pressure Control, Inc., Dallas, Texas.

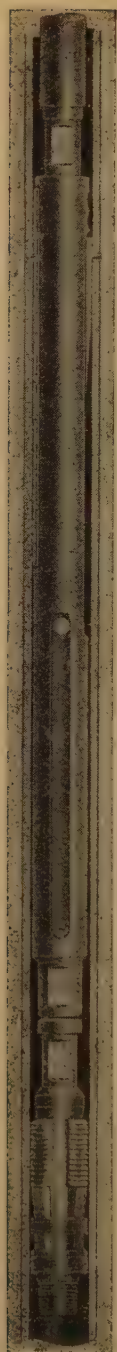


FIG. 1.—WIRE-LINE TUBING PERFORATOR WITH ORIFICE INSERT IN PLACE.



FIG. 2.—WIRE-LINE TUBING PERFORATOR, TYPE L.



accuracy, primarily because small holes ranging from $\frac{1}{32}$ to $\frac{1}{8}$ in. in diameter were being required. To overcome this deficiency, removable pack-off anchors containing orifices of desired size were set over the perforations to regulate the admission of gas into the tubing. Although the pack-off anchors served this particular purpose satisfactorily, they restricted the tubing bore and prevented the lowering in the tubing of depth-pressure instruments, swabs, and other tools.

To make possible the maintenance of full tubing bore and still provide an orifice of the exact desired diameter, the perforator was revised and equipped with a plunger and bushing for driving into the tubing walls, and locking securely in place, a hardened insert containing an orifice. This revision removed all objections to wire-line perforating.

The wire-line perforator permits two men, equipped with a wire line and some hand tools, to perform in two to three hours an operation that previously had required four men equipped with a pulling unit, tubing tools, and a derrick or A-mast several days to perform. The tubing perforator has been used in more than 600 wells in the short time that has elapsed since its design was revised to allow the installation of orifice inserts.

DESCRIPTION OF PERFORATOR AND AUXILIARY TOOLS

The wire-line tubing perforator (Figs. 1 and 2) is a mechanically operated tool that is run on an ordinary steel measuring line into the tubing of a well, under pressure, to drive into the wall of the tubing, and securely lock in place, a tapered, cylindrical insert containing an orifice. To facilitate the operation of the tool, however, several auxiliary tools are required: (1) collar finder, (2) removable stop, (3) knuckle joint, (4) tubing jars and stem. All of these tools are connected together and one insert is installed by each round trip.

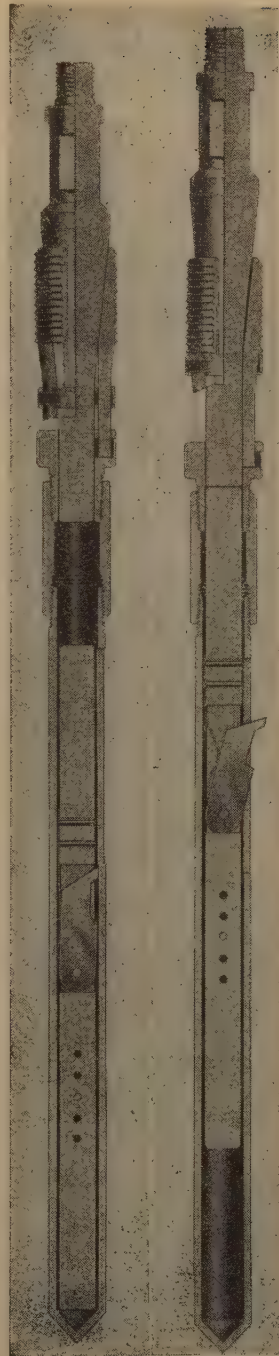


FIG. 3.—REMOVABLE STOP AND COLLAR FINDER IN SET POSITION (LEFT) AND RUNNING POSITION (RIGHT).

Each of the tools plays an important part in the perforating operation.

The collar finder is the first tool made up in the perforating string of tools, and its

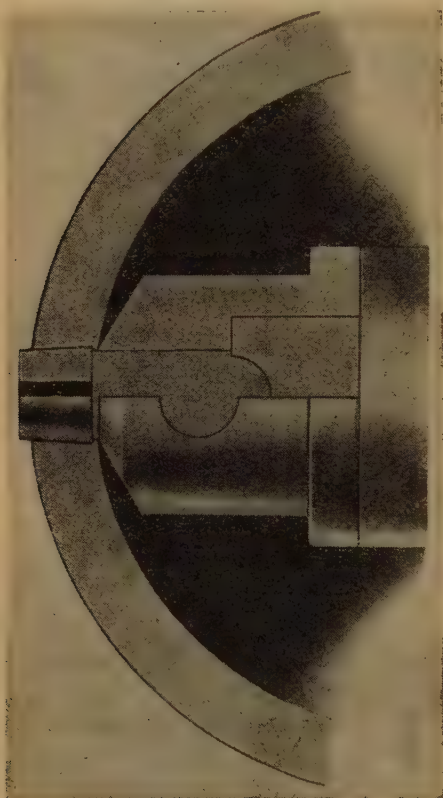


FIG. 4.—PERFORATOR ORIFICE INSERT AS IT IS DRIVEN INTO PLACE.

purpose, as the term implies, is to locate the tubing coupling nearest the perforating depth, which obviates the danger of attempting to perforate a tubing upset or tubing collar. The collar finder is simply a spring-loaded latch jack that travels freely down the tubing string, but hangs on the first coupling when pulled up the hole. This operation locates a collar in the desired perforating section and permits a specific depth to be selected for installing the insert. The collar finder is made inactive by swinging the tools upward about a coupling. This swinging action

shears a small brass pin as the latch hangs in the coupling, and forces the latch-jack assembly to drop into a cage.

The removable stop (Fig. 3) is attached to the upper end of the collar finder, and is used as a base to prevent downward movement of the perforator while the insert is being driven through the tubing wall. It consists primarily of three slips that expand over a tapered mandrel. While this tool is being run into the tubing, the slips are held in a retracted position by the collar finder, but as soon as the collar finder is made inactive, the slips are released and permitted to move freely over the tapered mandrel. Any downward jarring action after the stop has been set tends to set the slips more tightly, whereas upward impacts release the stop when its removal is desired.

The knuckle joint is made up on the upper end of the stop and provides flexibility and alignment if the tubing is corkscrewed or bent.

The tubing perforator (Fig. 1), consisting essentially of a housing, tapered wedge, base, and insert-holder assembly, is attached to the assembly above the knuckle joint and below the tubing jars and stem. After the stop is set, a downward jarring force on the upper end of the perforator cuts a small shear pin and allows the insert-holder assembly to contact the tubing walls. Further jarring action causes the tool to telescope and to drive the tapered wedge down between the tubing walls and the insert-holder assembly. An insert plunger and bushing within the insert holder transfers the impact of the jarring force to the orifice insert, and directs it through the tubing walls. To install another insert, it is necessary to pull the tools and place another insert in the perforator.

The tubing jars and stem are attached directly to the upper end of the tubing perforator, to complete the string of tools. Their function is to supply the jarring

action that causes the perforator to force the insert into the tubing walls. The jars also are used to release the perforator and stop so that they can be removed from the tubing. Regulation tubing jars are $1\frac{1}{2}$ in. o.d. with a 20-in. stroke, and the stem is usually $1\frac{1}{2}$ in. o.d. and 5 ft. in length.

OPERATION OF TUBING PERFORATOR

The wire-line tubing perforator (Fig. 1) and all the auxiliary tools are run into the tubing through a wire-line stuffing box and lubricator in much the same manner as a bottom-hole pressure bomb is run. The stop is set and the jars are operated by manual manipulation of the line at the surface. Ordinarily, about 80 downward impacts of the jars are sufficient to install an insert; jarring is continued, however, until the "feel" of the impact changes to a firm, solid thud. This indicates that the insert is in place and that the jarring impact is being applied directly against the face of the orifice insert holder. A few upward impacts of the jars release the stop and perforator and permit them to be removed from the tubing. Operators with wire-line perforating experience become very adept at "feeling" and "stroking" the jars, and can detect exactly the final stroke that drives the insert through the tubing wall (Fig. 4).

EXPLANATION OF MECHANICAL FORCES INVOLVED

During the early development of the tubing perforator many operators did not believe that sufficient mechanical energy could be developed with a small set of tubing jars to punch a hole through N-80 tubing. The total shear force required to punch the insert through the tubing wall was approximately 18,000 lb., and the energy had to be developed by repeatedly dropping a 30-lb. stem a distance of 20 in. Also, the jars and stem were to operate

at depths of several thousand feet, generally were submerged in fluid, and had to be actuated by manipulating the wire line at the surface. It was necessary, therefore, to design a tool that would give leverage to the force of the jarring action and also translate this downward force to a horizontal force. This objective was achieved through the use of a tapered wedge that was driven between an insert plunger and the tubing wall. The design was not made practical, however, until much experimenting eventually revealed the correct taper of the wedge, and the design of bearing surfaces that would give the greatest work efficiency and still permit the tool to be removed easily. From 50 to 100 downward impacts of the jars generally are required to install an insert, and usually from 5 to 10 upward impacts are required to release the perforator and stop.

LOCKING INSERT IN PLACE

The orifice insert (Figs. 5, 6, and 7) is slightly tapered so that the hole punched in the tubing is expanded as the insert is driven to its final position, which is $\frac{1}{32}$ in. beyond the inside diameter of the tubing. This taper sets up considerable stress in the tubing metal around the insert and permits the inside perimeter of the punched hole to shrink back of the insert, which locks it against backward movement. The taper, of course, prevents outward movement of the insert. So securely is the insert locked in place that a differential pressure of 7000 lb. per sq. in. across the insert in either direction will not dislodge the insert from its seat or cause a leak.

Equally important is the fact that the installation of the inserts in no way distorts the tubing. The bore of the tubing is left perfectly round with full opening and no obstructions to hamper swabbing or the running of any subsurface instrument (Fig. 6).

PREPARING FOR GAS LIFTING WELLS THAT
HAVE CASING ANNULUS LOADED
WITH MUD

Many wells in the Gulf Coast area were completed with a tubing-to-casing packer,

time these wells are ready for gas lifting, the bottom-hole pressures usually have declined to such an extent that the pressure in the producing formation is less than would be exerted by a column of water,

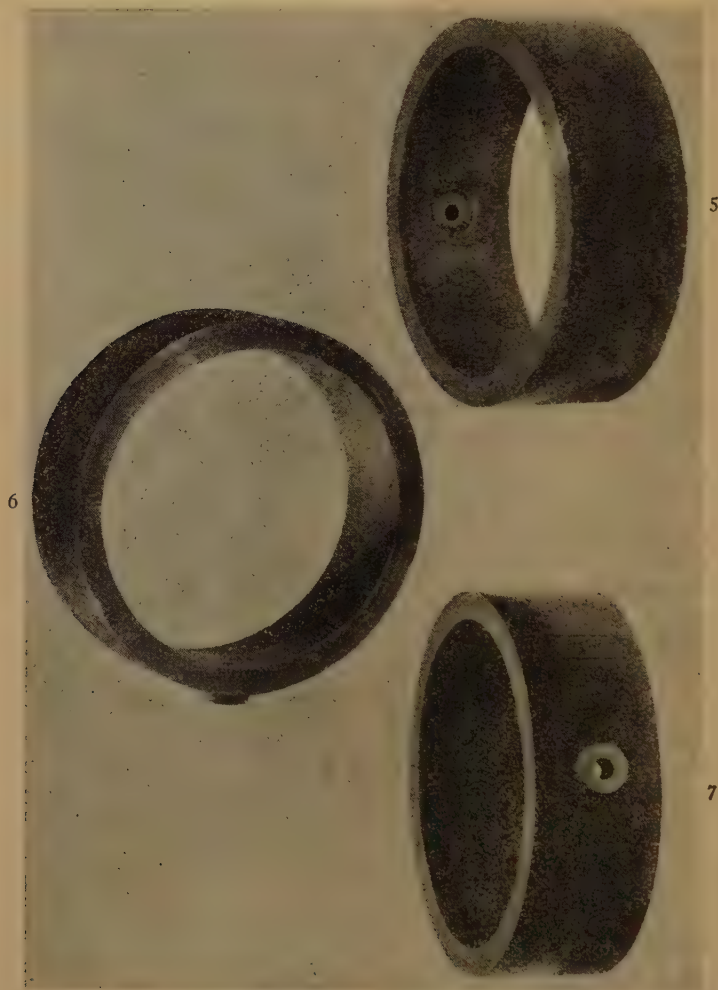


FIG. 5.—SECTION SHOWING INSERT DRIVEN $\frac{1}{32}$ INCH BEYOND INSIDE DIAMETER OF TUBING.
FIG. 6.—SECTION SHOWING TUBING BORE AT INSERT.
FIG. 7.—OUTSIDE VIEW OF INSERT IN PLACE.

leaving mud in the annular space between the tubing and casing (Fig. 9a). This has been the standard completion practice especially for high-pressure wells and for wells in or near bodies of water. By the

or the pressure required to start circulation without breaking down and permitting fluid to penetrate the formation. As the infiltration of extraneous fluid into a producing formation is very undesirable,

the risk of damaging the producing formation by mud-laden fluid had to be eliminated.

By making use of a removable check valve (Fig. 8), a procedure to remove the mud from the annulus and to install gas-lift jets without moving the tubing string, breaking the packer seal or exposing the oil-producing strata to the mud column, was devised (Fig. 9). This procedure is being used quite extensively through the Gulf Coast area.

In general, the preparatory work consists of installing with an ordinary steel measuring line the following tools: (1) the removable stop, just about the packer; (2) tubing check valve, directly above the stop; and (3) tubing perforator on top of the check valve. For the operation of punching a large hole to establish circulation, the tubing perforator is equipped with a special plunger that punches one $\frac{3}{8}$ -in. diameter hole in each operation. This arrangement of the tools is shown in Fig. 9b. The removable tubing stop (Fig. 3) serves as a base to prevent downward travel of the check valve and the tubing perforator. The check valve (Fig. 8) prevents the downward flow of mud or water into the oil-producing formation. The tubing perforator, of course, is the instrument for punching the hole or holes through the tubing walls. Before jarring action is started on the tubing perforator, the tubing is filled with water and sufficient pressure is applied at the surface to offset the greater pressure exerted by the mud column at the perforating depth. This practice is a safeguard to prevent the mud in the annulus from flowing into the tubing and sticking the tools after the hole has been punched. The pressure applied to the tubing at the surface is maintained until the tubing perforator is removed from the well. Circulation is established by pumping water into the tubing, causing mud in the annulus between the tubing and the casing to be

washed out (Fig. 9c). Water remaining in the tubing and casing is swabbed out and the oil is permitted to seek its natural static level. The check valve is then pulled and, if desired, the tubing perforation is closed by the installation of a pack-off anchor (Fig. 10), which latches directly on the stop. The more general practice, however, is to remove all the tools and install the orifice inserts at the desired depth. All of these operations are accomplished with the same steel measuring line.

GENERAL GAS-LIFT PRACTICE

In many wells, the tubing "loads up" with liquid and the wells cease to flow, although the gas pressure on the casing may be as much as 1200 lb. per sq. in. The wire-line tubing perforator has been used quite extensively in wells of this type, to install orifice inserts in the tubing string for the purpose of utilizing the gas to "kick off" the wells. Although this practice cannot be considered a permanent gas-lift installation, many times it has caused wells to flow continuously for several months before it became necessary to inject gas.

Another use for orifice inserts has been found to utilize casing gas from a packed off gas cap, or overlying gas zone, to assist in flowing oil from a lower zone. This type of installation is more economical, since it is not necessary to lay gas-injection lines or purchase gas for the operation.

In recent months a few inserts with built-in check valves have been installed to prevent back flow through the orifice. These installations were in two-zone, or dually completed, wells where the casing occasionally loads up and requires a small amount of gas-jetting to start flow again. The lower zone usually contains condensate-bearing gas that flows through the tubing whereas the upper zone contains oil that flows through the casing. For these

installations, check valves built into the inserts allow flow from the tubing into the casing, but prevent flow from the casing into the tubing. The flowing pressure on

the inserts if the installation of pumping equipment becomes necessary.

SELECTION OF ORIFICE SIZES AND DEPTHS OF INSERTS FOR GAS-LIFTING OPERATIONS



FIG. 8.—REMOVABLE CHECK VALVE.

the casing is somewhat higher than that on the tubing, consequently the check valves prevent flow through the orifice inserts under normal flowing conditions. If the casing loads up with liquid and the well ceases to flow, the tubing is closed in to allow pressure to build up. As the static tubing pressure approaches its peak, the gas pressure on the tubing becomes greater than the pressure on the casing, which causes the check valve in the insert to open and permit gas to flow from the tubing into the casing. As soon as the casing is unloaded and flow is resumed, the tubing is opened. With these favorable pressure conditions, check-valve inserts provide a simple and most economical means to "kick off" the liquid in the annulus, and also prevent comingling of fluids in the two zones during normal operations.

Inserts with built-in check valves that prevent flow from the tubing into the casing have been used in some gas-lift operations. The purpose of the check valves acting in this direction is to obviate the pulling and rerunning of tubing to remove

The appropriate depths at which inserts can be installed for gas-lift operations depend upon the pressure of the gas to be injected, the static fluid level in the tubing, and the gravity of the fluid to be lifted. When gas is injected in the annulus between the casing and tubing, the optimum depth for the uppermost insert is determined by calculating the maximum column of fluid that can be lifted by the pressure of the injected gas, working against the desired pressure to be maintained on the gas-oil separator. For wells that produce large quantities of salt water, these calculations are based upon the hydrostatic head of a column of pure salt water, because such a condition will exist frequently in the tubing string. Most injection pressures range from 500 to 1000 lb. per sq. in., therefore the depth of the uppermost insert usually is 1000 to 2300 ft. below the surface. As a rule, the installation of the first insert will cause the well to flow continuously; the general practice, however, is to install additional inserts at intervals of approximately 1000 ft. below the uppermost insert. This practice is logical because, as the column of fluid in the tubing above the uppermost insert becomes aerated and lightened by the injected gas, the resultant decrease in hydrostatic pressure permits gas to pass progressively through the second, third, and final inserts, which lie below the first, or uppermost, insert. As this practice permits the lifting of fluid from greater depths, a larger volume of fluid can be flowed from the reservoir.

The static fluid level ordinarily is near the surface, but several wells with fluid levels as low as 4000 ft. have been gas-lifted successfully, with injection pressures

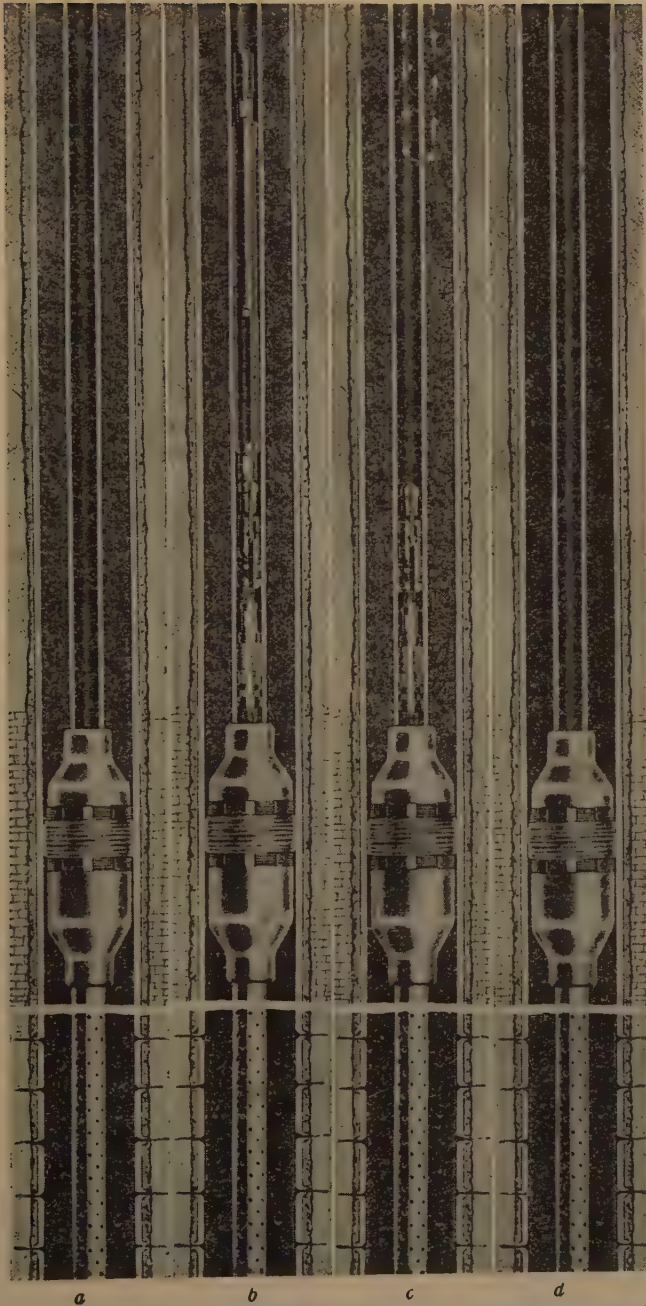


FIG. 9.—PROCEDURE IN REMOVING MUD FROM CASING WITHOUT EXPOSING PAY ZONE TO MUD COLUMN.
a. Mud in annular space before perforating operation is started.
b. Installation of stop, check valve and perforator.
c. Perforator removed and circulation established.
d. Well after mud has been circulated from annulus and all tools removed.

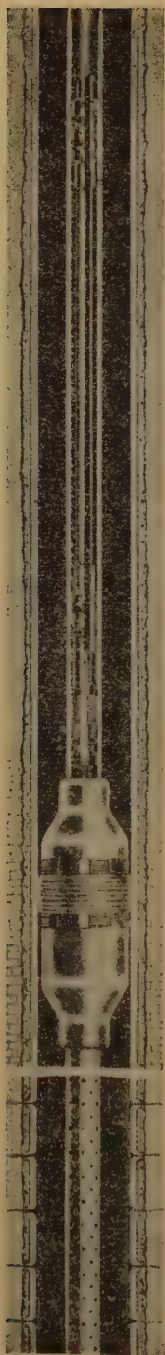


FIG. 10.—OTIS REMOVABLE PACK-OFF ANCHOR BEING USED TO CLOSE PERFORATIONS.

of only 400 to 600 lb. per sq. in., after orifice inserts were installed. This type of operation requires either the placing of inserts at closer intervals or the use of slightly larger orifices in the inserts. The inserts are installed at calculated depths, even though some of them may fall above the static fluid level. It is necessary for one or more of the inserts to be submerged below the fluid level to start movement of the fluid up the tubing, where gas flowing through each insert can lighten and increase the velocity of the flowing stream. Lifting fluid from a considerable depth with low-pressure injection gas can be accomplished simply by introducing into the fluid column a sufficient volume of gas to cause the "head" to be lightened to such an extent that fluid will flow from the reservoir.

The selection of the size of orifice, or orifices, depends upon the volume of fluid to be lifted and the pressure of the injection gas. It is virtually impossible to calculate before it is installed, with any degree of accuracy, the volume of gas that actually will pass through an orifice insert. Because of the fluid column in the tubing, usually a very small differential pressure is built up across the orifice inserts; consequently, critical-flow conditions usually do not exist across the orifice. To calculate gas volumes under these conditions, it is necessary to know the downstream pressure, and since no means are available to predetermine this pressure, it must be estimated. Furthermore, as the shape and size of the opening through the insert combine the characteristics of an orifice and a tube, regular orifice formulas will not suffice. Operators now have had so much experience in the perforation of tubing for gas lifting that generally they can select the correct size of orifice, or orifices, to give the desired results, by studying completion and production records of the individual well.

The following formula has been worked out in the laboratory of the American

Meter Co. for the flow of gas through these small orifice inserts, and has proved most helpful.

$$Q = 1842D^2T_f \sqrt{H(P + 0.15H)}$$

where

Q = cubic feet of gas (s.g. = 0.60) an hour.

D = diameter of orifice, inches.

T_f = temperature factor.

H = differential across orifice, pounds.

P = downstream pressure, pounds absolute.

Flowing Temperature Factors, T_f

DEG. F.	FACTOR	DEG. F.	FACTOR
100.....	0.9636	160.....	0.9158
110.....	0.9551	170.....	0.9085
120.....	0.9469	180.....	0.9014
130.....	0.9388	190.....	0.8944
140.....	0.9309	200.....	0.8876
150.....	0.9233		

Because of varying well conditions within a field, the required orifice sizes and depths vary to some extent even in offset wells. The commoner installations in a few important fields are listed in Table 1.

TABLE 1.—Some Installations of Wire-line Tubing Perforators

Field	Location	1st Insert		2nd Insert		3rd Insert		4th Insert	
		Size, In.	Depth, Ft.	Size, In.	Depth, Ft.	Size, In.	Depth, Ft.	Size, In.	Depth, Ft.
Conroe.....	South Texas	$\frac{3}{8}$ "	4,000	$\frac{3}{8}$ "	1,700				
Thompson.....	South Texas	$\frac{3}{8}$ "	1,850						
S. Houston.....	South Texas	$\frac{3}{8}$ "	3,000	$\frac{3}{8}$ "	1,500				
Hastings.....	South Texas	$\frac{3}{8}$ "	2,500	$\frac{3}{8}$ "	2,200	$\frac{1}{2}$ "	1,500		
Midway.....	South Texas	$\frac{1}{2}$ "	2,500	$\frac{1}{2}$ "	1,500	$\frac{1}{2}$ "	800		
Segno.....	South Texas	$\frac{3}{8}$ "	3,800	$\frac{3}{8}$ "	2,000	$\frac{3}{8}$ "	1,800		
League City.....	South Texas	$\frac{3}{8}$ "	1,800						
Hardin.....	South Texas	$\frac{3}{8}$ "	5,900	$\frac{3}{8}$ "	5,300				
Tomball.....	South Texas	$\frac{3}{8}$ "	3,500	$\frac{3}{8}$ "	2,800	$\frac{3}{8}$ "	1,900		
Friendswood.....	South Texas	$\frac{3}{8}$ "	2,000						
Fannett.....	South Texas	$\frac{3}{8}$ "	4,000	$\frac{3}{8}$ "	2,000	$\frac{3}{8}$ "	1,500		
Magnet.....	South Texas	$\frac{3}{8}$ "	2,000						
Maubro.....	South Texas	$\frac{3}{8}$ "	2,000						
Refugio.....	Southwest Texas	$\frac{1}{2}$ "	3,500	$\frac{3}{8}$ "	2,500	$\frac{1}{2}$ "	1,500		
Lolita.....	Southwest Texas	$\frac{1}{2}$ "	3,000	$\frac{1}{2}$ "	2,500	$\frac{1}{2}$ "	1,800		
Ben Bolt.....	Southwest Texas	$\frac{3}{8}$ "	3,500	$\frac{3}{8}$ "	2,000	$\frac{1}{2}$ "	1,000		
North Sweden.....	Southwest Texas	$\frac{1}{2}$ "	3,200	$\frac{1}{2}$ "	2,300				
Heyser.....	Southwest Texas	$\frac{3}{8}$ "	3,200	$\frac{3}{8}$ "	2,600	$\frac{3}{8}$ "	1,800		
Luvy.....	Southwest Texas	$\frac{1}{2}$ "	3,200	$\frac{1}{2}$ "	2,400	$\frac{1}{2}$ "	1,600		
Aransas Pass.....	Southwest Texas	$\frac{1}{2}$ "	7,500	$\frac{1}{2}$ "	4,700	$\frac{1}{2}$ "	3,700	$\frac{1}{2}$ "	3,400
Iowa.....	South Louisiana	$\frac{3}{8}$ "	4,000	$\frac{3}{8}$ "	3,500	$\frac{3}{8}$ "	2,500	$\frac{3}{8}$ "	2,000
Holly Ridge.....	South Louisiana	$\frac{3}{8}$ "	5,500	$\frac{3}{8}$ "	2,500	$\frac{3}{8}$ "	1,500		
Eunice.....	New Mexico	$\frac{1}{2}$ "	3,600						
Monument.....	New Mexico	$\frac{1}{2}$ "	3,750						
Hobbs.....	New Mexico	$\frac{3}{8}$ "	3,600						
Denver City.....	West Texas	$\frac{3}{8}$ "	4,900						
Sundown.....	West Texas	$\frac{1}{2}$ "	4,250	$\frac{1}{2}$ "	3,750	$\frac{1}{2}$ "	3,250	$\frac{1}{2}$ "	2,750

CONCLUSION

This paper should be regarded as a progress report on a wartime emergency tool. The wire-line perforator has been so successful, however, that many oil operators in the Southwest have adopted it for preparing oil wells for gas-lift operations. The saving in manpower and time has been important, but the greatest benefit from the use of the tool has been the removal of mud from the annulus between the tubing and casing, above a tubing packer, without permitting a column of mud to come in contact with the oil-producing strata.

The wire-line tubing perforator is applicable for converting any well to a gas-lift operation; however, it has not and certainly will not completely supplant the regular gas-lift valve. Unlike most flow valves, the wire-line perforator does not provide a means to control the kick-off pressures or to intermit or regulate the induction of gas into the tubing string. In this respect, the practice discussed in this paper is deficient; but during these times

of shortages the other advantages far outweigh this deficiency. Undisclosed applications and uses of the wire-line tubing perforator very likely will require revisions and improvements in design.

ACKNOWLEDGMENTS

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Behavior and Control of Natural Water-drive Reservoirs

By GEORGE R. ELLIOTT,* MEMBER A.I.M.E.

ABSTRACT

METHODS are presented for measuring and comparing "degree" of water drive, and for observing the control that rate of withdrawal exerts over decline of reservoir pressure.

Degree of water drive is studied from pressure-production curves of 10 reservoirs; the method used to present these comparatively is to convert cumulative oil production from barrels to percentage of ultimate. Degree of water drive is also represented by a "water-encroachment factor," representing barrels of water influx per pound-month per acre-foot of oil reservoir.

Pressure-production curves for the water-drive reservoirs after a period of declining pressure show a diminishing angle of slope, in some cases to the point where pressure ceases to decline or where it even increases; the shapes of these curves are in marked contrast to the dissolved-gas type of curve, which shows a general trend toward zero pressure at ultimate oil recovery.

Yearly rate of oil production in percentage of ultimate oil recovery is correlated with pressure decline. The correct rate of production of oil with its associated gas and water sustains pressure in reservoirs having a high water-encroachment factor. For reservoirs having a low water-encroachment factor, it is necessary to inject the produced water and even inject large volumes of water from an outside source.

The discussion of the actual reservoirs is preceded by a general review and is followed by a substantial bibliography.

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* Phillips Petroleum Co., Bartlesville, Oklahoma.

INTRODUCTION

It is now generally accepted that water drive is capable of yielding 60 to 80 per cent of the original oil in place in most reservoirs, as compared with 20 to 40 per cent for dissolved-gas drive. There is no need to question the importance of controlling a reservoir in order to take advantage of such an efficient mechanism.

What is a water-drive reservoir? Oil reservoirs usually combine two or more of the four basic mechanisms: dissolved-gas drive, gas-cap drive, water drive, gravity drainage. A water-drive reservoir is one in which water advances to take the place of the oil and gas produced. When the oil withdrawal rate is sufficiently low, the water will tend to maintain pressure. The maximum effectiveness is attained when the water follows the oil withdrawal so closely that little or no decline in pressure occurs.

Oil in its underground reservoir is associated with water. This water is significant in the production of the oil according to the source of supply and the permeability of the surrounding formation. As oil is produced and the pressure is lowered, water can move in to replace the oil. With adequate supply and sufficient permeability, actual movement takes place on an extensive scale.

The first movement of water takes place by expansion of the water and its associated fluids. While this expansion is of little importance in some fields, in others it is sufficient to supply all of the energy required for the production of oil. When a pressure differential has been established

between the oil reservoir and the outcrop of the productive formation, or any point at which extraneous water may enter, there is a tendency to set up a condition of steady flow; i.e., one in which the supply of extraneous water balances the fluid withdrawal from the field.^{13,16,23}

Capillary forces at the water-oil interface tend to displace the oil with water (assuming the reservoir rock to be "water wet"). The magnitude of the capillary forces is greater in the less permeable sands. In some reservoirs it is possible to produce at a low enough rate so that capillary forces are an important factor. When this rate can be attained, more regular movement of water results.

As water replaces the oil, it tends to maintain the reservoir pressure. For most reservoirs there is a withdrawal rate that will permit the encroaching water to maintain pressure or to achieve a slow pressure decline. In some cases this withdrawal rate will be commercially attainable and such fields may be produced with an "effective" water drive and will approach maximum economic recovery.

Two distinct concepts are to be recognized in considering water drive: water expansion and artesian flow. The expansion mechanism can operate in any oil reservoir; being most effective where the total volume of edge water is large (as in East Texas). In a lenslike reservoir expansion drive can exist but artesian drive cannot. A blanket reservoir cut by faults may perform as does a lens-type reservoir. No histories are available of pools where an important part of production resulted from artesian water drives; on the other hand, the number of studies of expansion water-drive pools steadily increases.⁶⁰

EFFICIENCY OF WATER DRIVE

As long ago as 1880, Carrl¹ said: The flooding of an oil district is generally viewed as a great calamity, yet it may be

questioned whether a larger amount of oil may not be drawn from the rock in that way than in any other; for it is certain that all the oil cannot be drawn from the reservoir without the admission of something to take its place.

Two Russian investigators¹⁰ presented some of the earliest actual figures on the efficiency of recovery under water drive. In many California fields, water drive was early recognized as an efficient recovery mechanism.^{13,16,23}

Laboratory flooding of cores of North Texas Pennsylvanian sand obtained residual saturations 12.3 to 17.5 per cent.⁴⁶ It was estimated that the residual oil saturation after field water-flooding would be in the order of 17 to 20 per cent. It was considered that practically all of the recoverable oil would have been removed from a segment of formation located at a point estimated at from 12 to 15 ft. behind the front of an advancing water drive in one case and 25 to 40 ft. in another case.

The ratio between the viscosity of oil and that of water causes water displacement to be inherently more effective than gas and to result in the recovery of a relatively large percentage of the oil in place prior to the time that the water front breaks through. Water drive is capable of yielding 60 to 80 per cent of the oil in place in most sands.⁵⁸

INFLUENCE OF PERMEABILITY VARIATION

As early as 1916, McMurray and Lewis³ drew cross sections to show the effect of the difference in porosity of sands on the extraction of gas and invasion of water, and how water came in and flooded the sand through the most porous streaks. In 1921, Mills⁵ studied the behavior of oil and water in a sand as oil is withdrawn through wells. His experiments showed that water flowing through the coarse sands advanced ahead of the oil and entered the fine sands, producing a water cone and rendering the

¹⁰ References are at the end of the paper.

fine sands around the well more permeable to water but less permeable to oil. The effect was to retard the movement of the remaining oil to the well. It was not until about 15 years later that this subject of relative permeability to oil and water became an important phase of reservoir study.

Other experiments,⁶ about 1920 to 1922, showed that water invading an oil-saturated sand body composed of a relatively coarse-grained and a relatively fine-grained sand displaced (within certain limits) the oil from the coarse sand and not from the fine sand. Twelve years after studies by Mills, similar experiments²² showed the tendency of water to by-pass oil in more finely grained layers, this tendency increasing with the increase in the difference of permeability between the separate sand layers.

The relationship between capillary pressure, water saturation and permeability is such that the tendency is for the fine sands always to maintain higher water saturation at equilibrium than the adjacent coarse sands at the same level.⁴² The complexity of natural reservoirs prohibits formulation of any single connoted expression relating over-all flushing efficiency to the rate of production, or to any of the other pertinent variables. The factors involved, however, may be illustrated in a qualitative fashion by considering the behavior of a small lens of tight, fine sand embedded in a coarse, more permeable sand some distance above the original water table. If the rate of production allows the water table to rise slowly enough to permit the maintenance of capillary equilibrium, water saturation in the coarse sand will gradually increase simultaneously with the rise of the water table. As the water saturation in the adjacent coarse sand increases, the tight lens will imbibe water and expel oil, both by absorbing water at the bottom and expelling water at the top and by counterflow of water and oil over the entire surface of the lens, tending

always to maintain a higher water saturation than that reached by the surrounding coarse sand.

SIGNIFICANCE OF PRODUCTION RATE

Even to early investigators it became apparent that trapping of oil in sand bodies of low permeability might be avoided, or at least reduced, by lower rates of production. Water-encroachment rate in relation to efficiency of oil recovery was first discussed in A.I.M.E. publications in 1927.⁸

Muskat²⁵ included a study of the rates of encroachment of water into an oil sand with his study of two-fluid systems in porous media.

A graph drawn for East Texas field, showing calculated reservoir pressure and accumulative production for various constant production rates clearly brings out the possibilities of producing more oil at a higher average pressure level by using lower rates of production.³⁶

Under high rates of production⁴² a tight lens will become suddenly surrounded by a zone of high water saturation. Oil will escape from the tight sand but so slowly and into a region of such high water saturation that the oil will not be recovered. In time the lens will give up its oil but as a practical matter it may be considered that the oil is trapped and lost. For this particular situation, it is evident that the slower the rate of water advance, the higher the oil recovery.

There are two main controls of water encroachment: permeability, and rate of withdrawal.³² The removal of oil and gas lowers the pressure in the reservoir and the water surrounding the reservoir tends to move into the region of lower pressure. When the permeabilities of the rock are high enough and withdrawal rates are sufficiently low, this tendency of water may become an actual encroachment of such magnitude that the pressure is sustained in the oil reservoir. On the other hand, with low permeabilities and com-

paratively high withdrawal rate, no effects of water encroachment may be observed during the life of the pool, the pressures declining as though no water were present behind the oil accumulation.

It is necessary to reconcile two apparently opposed viewpoints as to the effect of rate of water encroachment. In most water-drive reservoirs, the oil formation is probably "water wet" and slow velocities will result in the greatest oil recovery. Where "oil-wet" conditions prevail, the possible greater efficiency of high velocities must be considered.

It is important to consider rate of water production along with oil-production rate in a water-drive reservoir.⁶³ Production at a high pressure level is desirable to avoid the shift to dissolved-gas type drive. It is readily apparent that the production of water must be balanced with the oil-production rate against the pressure that is desired. If the oil rate is low, the water rate may be comparatively high without causing waste; on the other hand, if maximum oil rate is required, water production must be curtailed.

DEGREE OF WATER DRIVE

Degree of water drive is influenced by both natural conditions and operating conditions. Natural conditions are: (1) the gas-oil relationships, (2) character of the aquifer, (3) permeability. Operating conditions are functions of the withdrawal rate.

The gas-oil relation in the reservoir indicates whether the reservoir crude was initially saturated or undersaturated; if saturated, whether or not there was an original gas cap, and if so its size relative to the oil-saturated portion of the reservoir.

The character of the aquifer refers to the extent of the water body, whether the source of the water that moves into the oil reservoir may be regarded as an infinite source or whether the source must be considered as so limited that water encroachment becomes a diminishing factor.

Permeability includes permeability of the formation constituting the oil reservoir, permeability of the water-saturated formation surrounding the oil reservoir, and particularly the permeability of the border zone through which the water moves into the oil zone.

Fig. 1 is a group of curves of reservoir pressure plotted against cumulative oil production. The largest reservoir size represented on this graph is almost 1000 times the size of the smallest. In order to draw these curves so that their shape may be comparable, the cumulative oil production has been converted from barrels to percentage of ultimate oil recovery. It is not necessary that the ultimate oil recovery, or original reserve, from which these curves are drawn shall be estimated within narrow limits; the figure used in each case may be considered a reasonable estimate, based upon the observed behavior of the reservoir. The result of this method is to place all reservoirs on at least a roughly comparable basis with respect to "degree" of water drive.

Ten of the curves in Fig. 1 represent water-drive reservoirs, recognizing that this term includes a range of widely varying reservoir behavior: Schuler (Reynolds), Arkansas; Magnolia, Arkansas; Buckner, Arkansas; Turkey Creek, Texas; Midway, Arkansas; Ramsey, Oklahoma; Hobbs, New Mexico; East Texas, Texas; East Watchorn, Oklahoma; Yates, Texas.

The steeply declining curve cutting across the upper half of the graph is a typical curve representing a dissolved-gas mechanism. This curve represents Schuler (Jones) before unitization and gas injection. Although a small gas cap was present originally and there was some water encroachment, this curve presents the distinctive character of dissolved-gas drive—a definite trend toward zero pressure at ultimate recovery. The Schuler (Jones) curve is in marked contrast to the water-drive curves, which after some decline in

pressure reduce their angle of slope in varying degree.

In three of the pools the natural water drive has demonstrated its ability to main-

If East Watchorn has reached pressure equilibrium it is after a decline of 385 lb. from 1450 lb.—a decline of approximately 27 per cent.

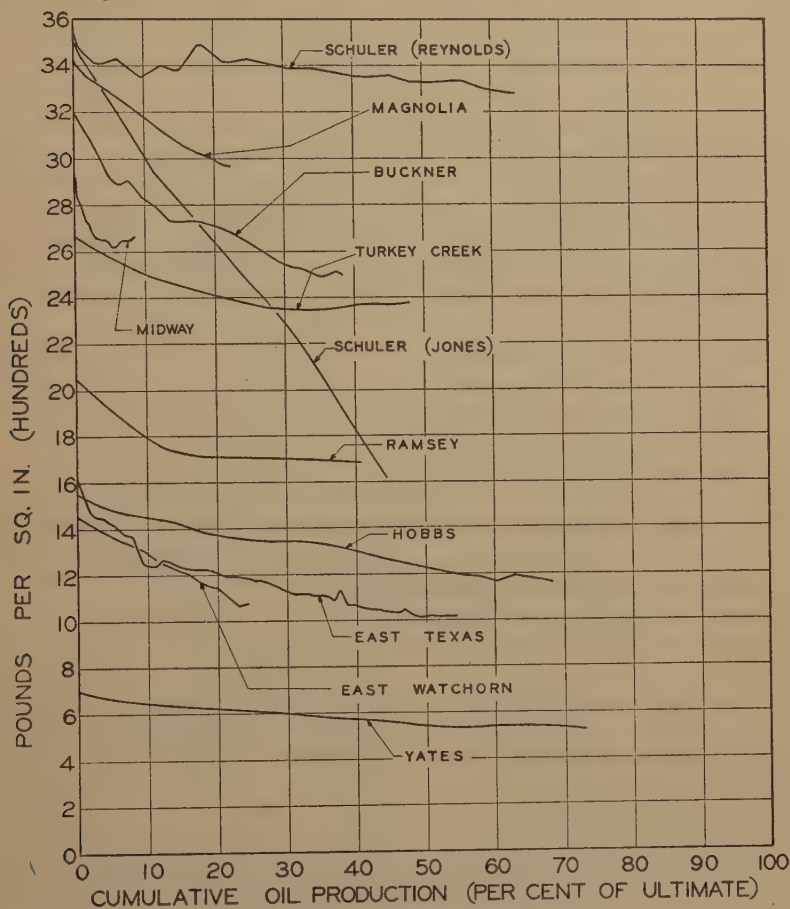


FIG. 1.—PRESSURE-PRODUCTION CURVES.

tain the pressure to zero decline. Schuler (Reynolds), although more recently declining in pressure because of higher withdrawals, indicates pressure equilibrium after a decline of 150 lb. from 3550 original. Turkey Creek reached pressure equilibrium at 310 lb. decline from 2660 lb. original. Ramsey shows pressure equilibrium after a decline of 350 lb. from 2050 original. These percentage declines are 4, 12, and 17, respectively.

East Texas, with the support of its water injection, reached pressure equilibrium when reservoir pressure had declined from 1600 to 1008 lb., or 37 per cent.

In two pools where the natural water drive was inadequate to maintain pressure to zero decline under prevailing withdrawal rates, the injection of water has sustained the pressure. In Midway the present maintenance of pressure is due to

injection of water from an outside source. In East Texas, the injected water is water that has been produced from the reservoir.

In order to calculate a water-encroachment factor, it is assumed that the pressure in the water bodies surrounding oil reservoirs will remain at the original pressure and that the rate of water encroachment will be directly proportional to the difference between the reservoir pressure at any time and the original pressure. For a particular production period, in months, the amount of water encroached will be the product of the length of the period, the average pressure differential, and a water-encroachment factor K . At the end of any given period, the accumulated water encroachment is the sum of the amount of water encroached during each of the preceding periods; it is expressed in multiples of K . To determine the value of K , it is necessary to consider several pressure-production periods, and solve a series of functions involving n (original oil in place) and K ; for example, material-balance equations for East Watchorn for 12 pressure periods reduce to the following:

$$\begin{aligned}n &= 31,583,500 - 11,160K \\n &= 33,701,200 - 13,413K \\n &= 35,076,600 - 16,127K \\n &= 35,357,800 - 18,385K \\n &= 35,762,500 - 19,578K \\n &= 36,431,000 - 21,867K \\n &= 39,776,000 - 25,827K \\n &= 40,663,000 - 29,699K \\n &= 40,311,800 - 30,126K \\n &= 40,193,000 - 31,456K \\n &= 42,018,500 - 34,589K \\n &= 37,858,700 - 34,024K\end{aligned}$$

The 12 equations are added; also, the same equations are multiplied by their respective coefficients of K and then added, yielding the following pair of equations:

$$\begin{aligned}12n + 286,251K &= 448,733,600 \\286,251n + 7,564,238,135K &= 10,972,206,698,200\end{aligned}$$

Solving simultaneously for K ,

$$K = 364$$

K represents barrels of water encroachment per month for each pound of pressure differential between the reservoir pressure at a given time and the original reservoir pressure. To arrive at an encroachment factor (K_a) that can be used to indicate "degree" of water driven when comparing one reservoir with another, K is divided by the acre-feet of oil reservoir.

Factor K_a has been calculated for other pools as described later.⁶⁰ The values are shown here to correlate with Fig. 1:

Schuler (Reynolds).....	0.0860
Magnolia.....	0.0021
Buckner.....	0.0036
Turkey Creek.....	0.0426
Ramsey.....	0.0300
East Watchorn.....	0.0107

RATE OF WITHDRAWAL

The following pages contain a discussion of individual reservoir behavior and the influence of withdrawal rate on pressure decline.

Schuler (Reynolds)

The Reynolds limestone consists of spherical oölites ranging in size from very fine to coarse, and loosely cemented. Permeabilities as high as 15,000 millidarcys are found. A typical producing section of 50 ft. totals 35,000 ft.-md. The reservoir crude was saturated at the initial pressure. An original gas cap occupied 10 per cent of the reservoir volume. Expansion of the gas cap caused by pressure decline has been mostly offset by production of gas-cap gas; hence there has been little net change in the size of the gas cap.

Fig. 2 shows three curves plotted against cumulative oil production: reservoir pressure at the end of each three-month period; three-month daily average oil-production rate; three-month daily average oil-plus-water-production rate.⁶²

Around the one million cumulative oil point on the graph, at an oil-production

rate of about 2300 bbl. per day, the pressure has an upward trend. At that point, water production is becoming appreciable, and when about 800 bbl. of water per day

than is observed in the 1943 portion of the pressure curve; this trend represents 10,000 bbl. of oil produced per pound decline.

Water encroachment was calculated

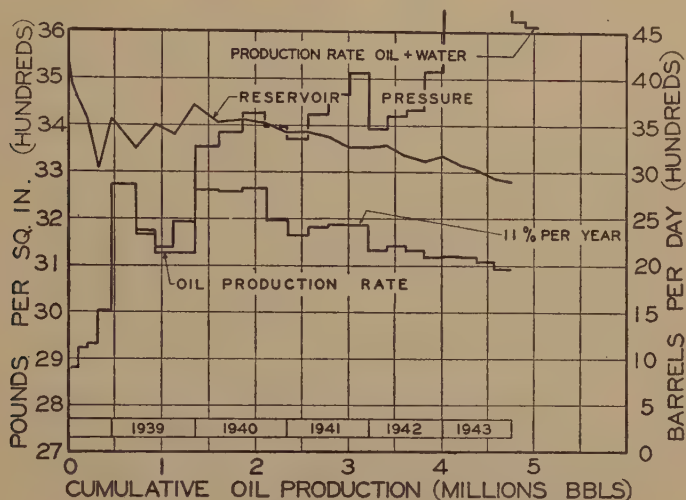


FIG. 2.—SCHULER (REYNOLDS) PRESSURE-PRODUCTION GRAPH.

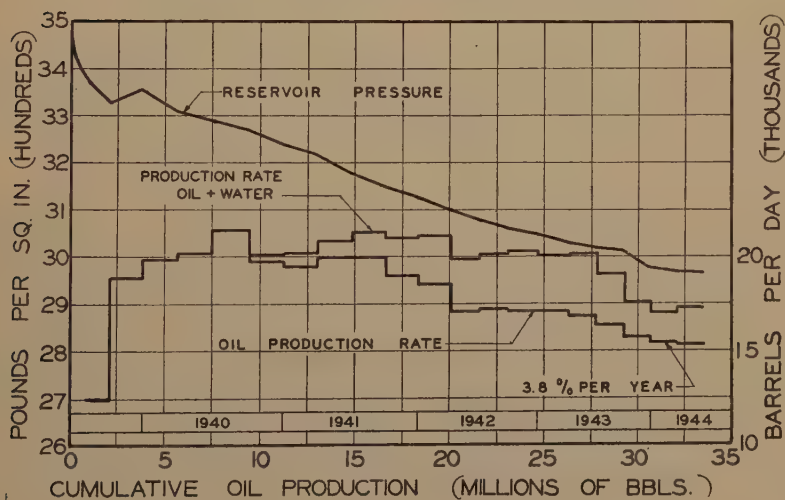


FIG. 3.—MAGNOLIA PRESSURE-PRODUCTION GRAPH.

is added to 2800 bbl. of oil, the pressure resumes a downward trend.

It is remarkable that with a yearly oil-withdrawal rate of 9 per cent of the ultimate, such a high water-withdrawal rate as 3800 bbl. per day added to an oil rate of 2000 results in no steeper downward trend

from material balance to be 45.4 bbl. per day per pound pressure differential between reservoir pressure at any given time and the original pressure.⁶⁰ This represents 1350 bbl. per pound-month. Dividing by 15,700 acre-ft. water-encroachment factor K_{a} is 0.086 bbl. per pound-month per acre-foot.

The graph indicates that about 2500 bbl. per day oil-production rate balances water encroachment. Adding shrinkage and water production, this corresponds to 4000 bbl. of reservoir space per day. Water-encroachment factor, calculated on that basis, is 0.051 bbl. per pound-month per acre-foot.

Magnolia

Reynolds (Smackover) lime production was discovered at Magnolia in 1938. Maximum thickness of main porosity is 283 ft., five times the maximum thickness in Schuler. Permeabilities are lower than in Schuler, reaching a maximum of 6740 md. The reservoir crude was saturated at the initial pressure.

Productive area inside the 7321 subsea contour (original oil-water contact) is 4675 acres. Maximum closure on top of Smackover limestone is 321 ft.; gas-oil contact 7246 subsea. Gross volume of the reservoir in the main porosity below gas-oil contact is 523,000 acre-ft.; volume of gas cap, 74,000 acre-feet.⁵⁵

Fig. 3 includes the same type of pressure and production curves as Fig. 2, plotted for three-month intervals against cumulative oil production.

Water production for February 1940 was 1015 bbl., or 35 bbl. per day; this accompanied 19,900 bbl. of oil per day. Water production for December 1942 (approximately 25 million barrels cumulative oil) had increased to 3220 bbl. per day, or 16 per cent of the fluid produced. Calculated volume of water encroached to Jan. 1, 1942, is 12,200,000 bbl.,⁵⁶ which, divided by 11,057 pound-months resulted in K equal to 1130 bbl. per pound-month. Dividing by 523,000 acre-ft., encroachment factor (K_a) is 0.0021 bbl. per pound-month per acre-foot.

Fig. 3 shows that oil-production rate of approximately 20,000 bbl. per day was maintained until about 17 million barrels of oil had been produced, representing the

year 1940 and most of 1941. This represents a yearly oil rate of about 5 per cent of the original reserve and a pressure-production trend of 68,500 bbl. produced per pound pressure decline. During the period beginning March 1942 (20 million cumulative oil production) a 17,000-bbl. daily oil-production rate prevailed, representing a yearly withdrawal rate of 4.2 per cent of the original reserve. During that period, 115,000 bbl. per pound was the pressure production trend. For the second quarter of 1944 (33 million cumulative oil) a withdrawal rate of 15,300 bbl. per day, 3.8 per cent per year (17,300 bbl. per day oil plus water) apparently comes close to balancing water encroachment and maintaining pressure.

Reduction of oil-withdrawal rate appears to flatten the pressure decline even though water production increases to maintain the total oil-plus-water rate. For example, from 10 to 13 million cumulative oil (October 1940 to March 1941); total oil-plus-water production rate was the same as from 20 to 27 million cumulative oil (April 1942 to June 1943), but the rate of decline is less for the later period.

Buckner

The three curves in Fig. 4 represent the same type of pressure and production data as in Figs. 2 and 3, shown for three-month intervals.

Reynolds (Smackover) lime was discovered in Buckner in 1937. Permeabilities are low. Oil-production rate has not fluctuated very widely; it has averaged about 2300 bbl. per day between the 1 million and 3 million barrels cumulative oil-production points that represent the years 1940 and 1941. From 3 million to nearly 4 million barrels cumulative oil, although the oil-production rate was lower, water production had increased to 400 bbl. per day; hence, total oil-plus-water production remained approximately the same from the beginning of 1940 to September 1943.⁶²

The calculated 4.2 bbl. per day water encroachment per pound⁶⁰ represents a water-encroachment factor (K_a) of 0.0036 bbl. per pound-month per acre-foot.

steep pressure decline. Later pressure behavior is not shown because the field went on gas-lift and pressure surveys were discontinued.

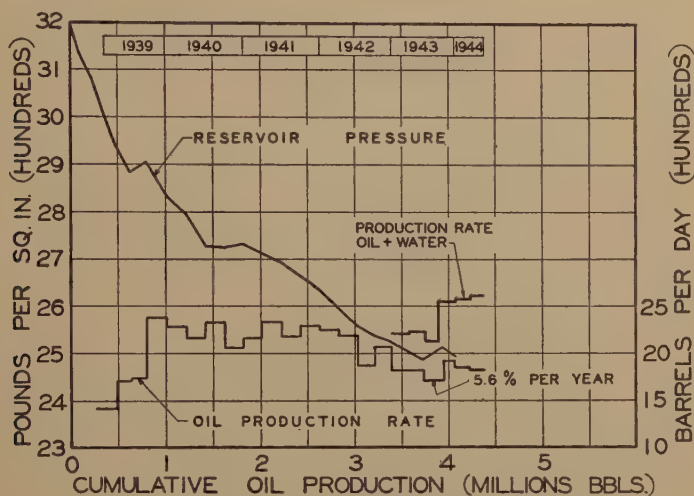


FIG. 4.—BUCKNER PRESSURE-PRODUCTION GRAPH.

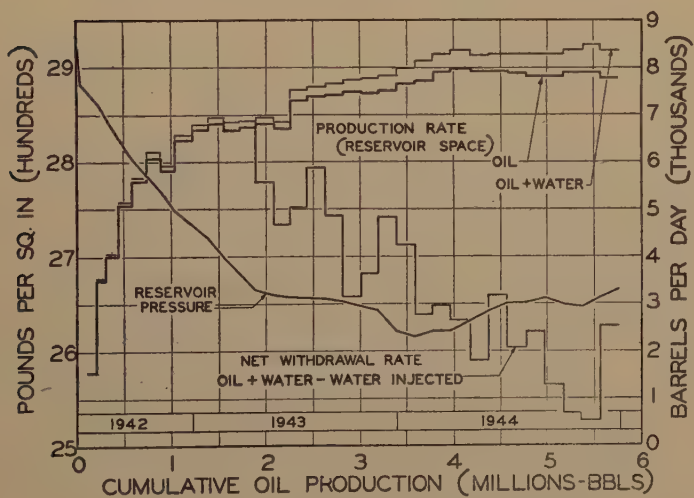


FIG. 5.—MIDWAY PRESSURE-PRODUCTION GRAPH.

Just before reaching 4 million barrels cumulative oil in the last quarter of 1943, water production is seen to increase sharply. The first three-month period following the abrupt increase in production rate of oil plus water is represented by a

Midway

Midway was discovered Jan. 1, 1942. It produces from the Reynolds oolite zone of the Smackover limestone. Area is approximately 1700 acres. Maximum thickness of oil column is 200 ft. Average permeability

is 520 md. There is no gas cap. Reservoir crude was initially undersaturated by 400 lb.; bubble point of the reservoir oil is 2528 lb. per sq. in. whereas the initial pressure was 2020 lb. per sq. inch.⁵⁵

water produced—less barrels of water injected. During the first five months, water injection averaging 2500 bbl. per day reduced the net withdrawal rate from 7500 to 5000 bbl. per day, which was

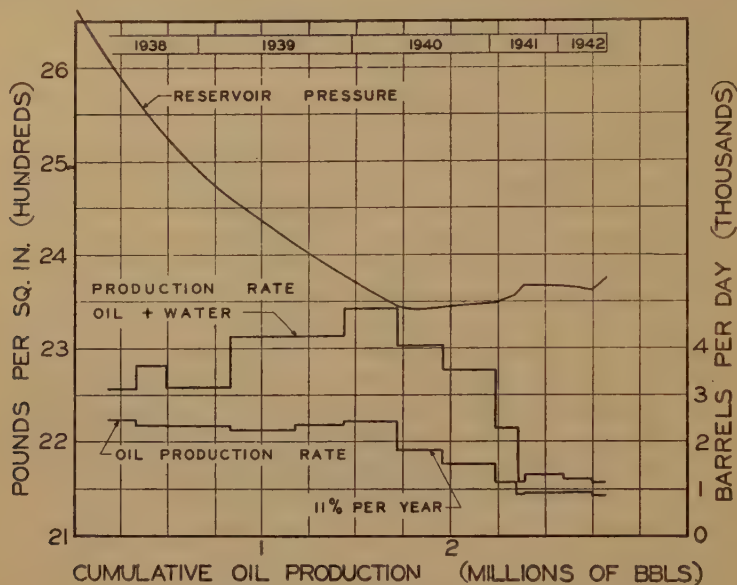


FIG. 6.—TURKEY CREEK PRESSURE-PRODUCTION GRAPH.

Referring to Fig. 5, during the 17 months from discovery to April 1943, reservoir pressure declined 255 lb. from 2020 to 2665 lb. per sq. in. during the production of a little less than 2 million barrels of oil. This decline is similar to that of Buckner in its early life. Production rate had reached 5600 bbl. per day, accompanied by 150 bbl. of water.

From this point on, this reservoir follows a distinctive course of behavior: beginning April 19, 1943, water was injected to sustain pressure and artificially supply the additional water required to enable the reservoir to be operated under water-drive control.

In Fig. 5, production rate, shown by months, is converted into terms of reservoir space voided by the oil and its solution gas plus water. The graph also shows net withdrawal—reservoir barrels of oil and

apparently low enough to sustain pressure to a decline of only a few pounds. After a further reduction to an average of 4000 net barrels per day, pressure declined 37 pounds.

A second water-injection well was connected in January 1944, and a third in March 1944. Injection averaging 5400 to 6400 bbl. per day from February to August 1944 reduced net withdrawal to between 2000 and 3000 bbl. per day, only about one third of the gross. Apparently there was sufficient natural water drive to increase the pressure 40 lb. during this seven-month period.⁶⁵

The water-injection rate continued to be increased and a fourth injection well was connected in October 1944. Yet the pressure resumed its decline, and it was not until nearly 8000 bbl. per day was injected in November 1944 that the pressures were

again increased. This increase corresponded to a net withdrawal rate of 505 bbl. per day, the volume returned being almost equal to the volume produced.⁶⁵

at about $2\frac{1}{4}$ million barrels cumulative oil was caused by the shutting in, early in 1941, of edge wells producing at high water-oil ratios.

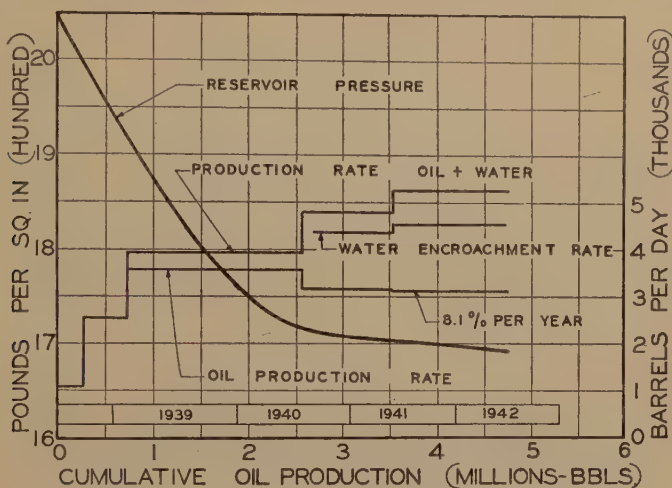


FIG. 7.—RAMSEY (WILCOX) PRESSURE-PRODUCTION GRAPH.

Turkey Creek

The Douglas sand of the Frio (Oligocene) was discovered in Turkey Creek in January 1938. The sand averages 17 ft. thick; permeabilities average over 3000 md. Total permeability in foot-millidarcys is about the same as in Schuler (Reynolds).

Fig. 6 includes the usual three curves plotted against cumulative oil production: reservoir pressure, oil-production rate, production rate oil plus water, for three-month periods.

During the production of the first half million barrels of oil, pressure production follows a straight-line decline of a dissolved-gas drive character for a decline of 100 lb. per sq. in. The curve then gradually flattens. From middle of 1938 to middle of 1940 (1 $\frac{3}{4}$ million cumulative oil) oil-production rate remained fairly constant at 2350 to 2450 bbl. per day. During this period, water production increased until the production of oil plus water during the first quarter of 1940 reached 4880 bbl. per day. The abrupt drop in water production

Apparently the oil-plus-water withdrawal rate of 4000 bbl. per day in 1940 allowed water encroachment to balance pressure decline. One year previous, in 1939 (at 1 million cumulative oil production), a considerably lower rate, 3100 bbl. per day, overbalanced water encroachment, and pressure decline followed a trend of about 6000 bbl. of oil produced per pound pressure decline. This is because at the beginning of the earlier period pressure had declined only 150 lb. per sq. in., while at the beginning of the later period pressure had declined more than 300 lb. per sq. in.; water encroachment being proportional to the decline from the original pressure.

From material balance, water-encroachment K equal to 235 bbl. per pound-month when divided by 5513 acre-ft. gives 0.043 for K_a .

Ramsey (Wilcox)

First Wilcox (Ordovician) production was discovered in the Ramsey pool in January 1938. The reservoir crude was

saturated at the time of discovery but no gas cap was present. Maximum productive thickness is 160 feet.

In Fig. 7 the pressure curve represents

production and 4790 bbl. per day production of oil plus water.

Owing to the degree of water drive, the pressure declines very slightly under oil

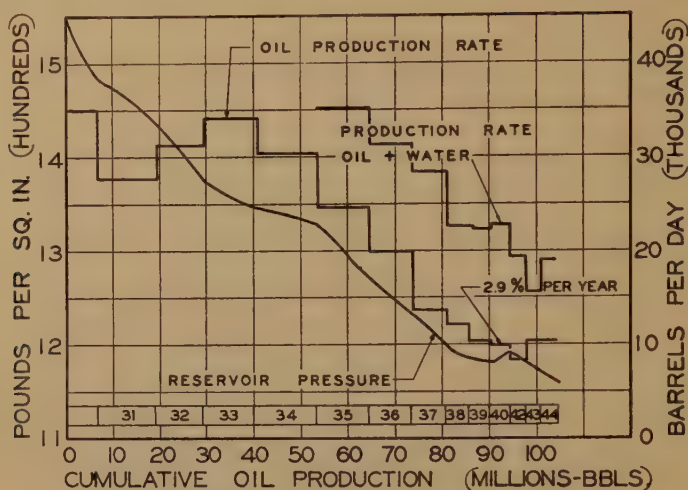


FIG. 8.—HOBBS PRESSURE-PRODUCTION GRAPH.

five pressure surveys beginning Sept. 1, 1938, and ending July 1, 1942. Curves for oil-production rate, production rate of oil plus water, and water-encroachment rate, represent average barrels per day for each period. The curve declines steadily until the pressure is about 300 lb. per sq. in. below the original, then becomes almost flat.

Pressure decline has continued at a very slow rate. The graph is not extended because of gas-injection operations after this time.

Barrels of water encroached per month per pound pressure differential between reservoir pressure at any given time and the original pressure was determined by simultaneous equations to be 391. Dividing by 13,216 acre-ft., encroachment factor is 0.0300 bbl. per pound-month per acre-foot. Water-encroachment rate in average barrels per day during the period between $2\frac{1}{2}$ and $3\frac{1}{2}$ million barrels cumulative oil production was calculated to be 4380. This compared with 3150 bbl. per day oil

withdrawal at the yearly rate of 8 per cent of ultimate, even when accompanied by water production at half the oil-production rate.

Hobbs

Hobbs was discovered in 1938; produces chiefly from the "White lime" of Permian age. The white lime consists of an upper highly porous dolomite, cavernous in many wells, and a lower, less permeable, dolomite zone; the porous dolomites are granular and frequently oolitic.¹⁸

An initial gas cap was present on top of the structure and expanded with the decline in pressure. Water encroached updip mainly through the highly permeable portions of the upper zone and advanced most rapidly on the southwest side of the structure, following closely the structure contour lines.³¹

Fig. 8 shows three curves plotted against cumulative oil production: reservoir pressure at the end of each year; average daily oil production and average daily oil-

plus-water production for each one-year period. The nearest approach to a withdrawal rate balancing reservoir pressure is at the 90 million cumulative point, where the pressure shows an increase correspond-

history, a declining reservoir pressure and also a downward trend of oil-production rate. It is necessary to compare with the net fluid-withdrawal curve for explanation of the behavior of the pressure curve.⁶⁸

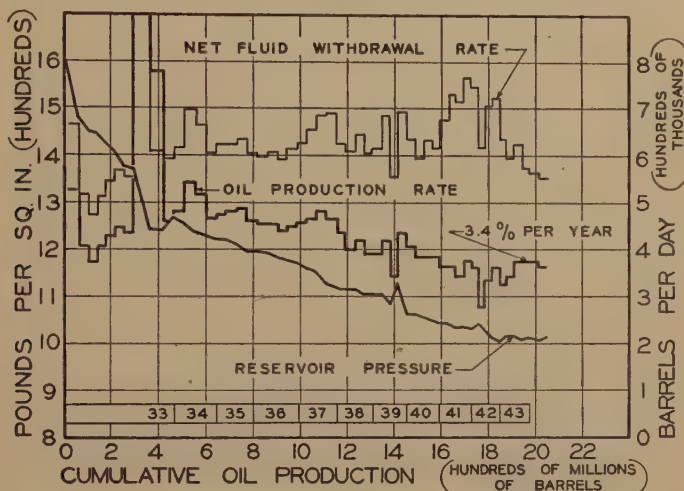


FIG. 9.—EAST TEXAS PRESSURE-PRODUCTION GRAPH.

ing to a withdrawal rate of approximately 10,000 bbl. per day, accompanied by an equal production of water. This oil-production rate represents a yearly withdrawal of 2.9 per cent of the ultimate. However, pressure resumes its decline later under no greater rate of withdrawal.

East Texas

The three curves in Fig. 9, plotted against cumulative oil production, are: reservoir pressure at the end of each three-month period; oil production and net fluid withdrawal rates, daily averages for each three-month period. Net fluid withdrawal is oil-gas-water production less water injection.

Permeabilities are as high as 13,000 md. and a typical 70-ft. section totals 350,000 foot-millidarcys.

The reservoir average pressure has remained above the saturation pressure of 740 lb., initially being 860 lb. above.

Fig. 9 shows, for most of the production

At 300 million barrels cumulative oil, the field was opened up to 982,000 bbl. per day, three-month average; this meant 1,249,000 bbl. per day net fluid withdrawal. Reservoir pressure took an abrupt drop as a consequence of this extremely high withdrawal rate.

It is apparent that at points where net fluid withdrawal was as low as 600,000 bbl. per day, pressure tended to be maintained. These points are seen at cumulative oil production 600 million, 900 million, 1200 million and 1300 million. At 1400 million, net fluid withdrawal dropped to 557,000 bbl. per day, causing a sharp increase in pressure from 1084 to 1128 lb. per sq. in. Just before the 1800 million point, a drop of oil rate to the lowest quarterly average ever reached, 279,000 bbl. per day failed to cause a pressure increase similar to that corresponding to a rate of 342,000 at the 1400 million point. The reason for this is apparent: because of the increased production of water, the net fluid withdrawal

had increased from 557,000 to 618,000 bbl. per day, although the oil production decreased.

The most recent period shown is one

Water-encroachment rate is calculated from the water-encroachment factor 364 bbl. per pound-month, derived as previously described.

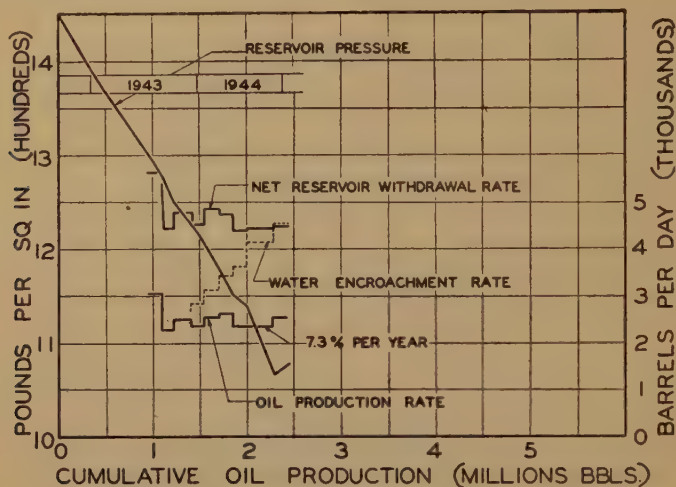


FIG. 10.—EAST WATCHORN PRESSURE-PRODUCTION GRAPH.

of zero pressure decline. Although the oil-production rate has not been reduced during the production of the last 200 million barrels, the injection of water has reduced the net fluid-withdrawal rate from 730,000 to 550,000 bbl. per day.

East Watchorn

East Watchorn, discovered in May 1942, produces from the Wilcox (Ordovician), 977 acres, 34,000 acre-feet.

Permeabilities range up to 1500 md., with a typical cored section of 15 ft. averaging about 250 millidarcys.

Reservoir crude was saturated at initial reservoir pressure 1450 lb. per sq. in. There was no original gas cap.

Fig. 10 includes four curves plotted against cumulative oil production, mostly for two-month periods. Reservoir pressure and oil-production rate are the usual curves. Net reservoir withdrawal rate is made up of reservoir space represented by: produced oil, gas in solution in the produced oil, excess gas (in solution in the reservoir oil), water, less water injected.

During the second half of 1943 and the year 1944, reservoir withdrawal rate (net) has remained between 4400 and 4800 bbl. per day. In the same period water-encroachment rate increased from 2500 to 4500 bbl. per day. For the last period shown, the two months ending Feb. 1, water-encroachment rate apparently equals net reservoir withdrawal rate. The accompanying increase in reservoir pressure needs support from a later pressure survey, but it appears to be a significant indication.

The injection of nearly all the produced water results in the reduction of withdrawal rate from 5300 to 4500 bbl. per day net.

Yates

Oil production in the Yates lime of Permian age was discovered in 1927. Since 1934, a Railroad Commission Rule has prohibited penetration greater than 225 ft. below the top of the "Brown" lime and the thickness of the gray productive lime formation is not known. There is no evidence of an original gas cap in the limestone

reservoir, but gas-cap areas formed as the pressure was reduced and gas came out of solution in the oil.

Fig. 11, in addition to reservoir pres-

2. Degree of water drive is calculated by material balance and also is observed from pressure-production graphs.

3. The method used to compare pools

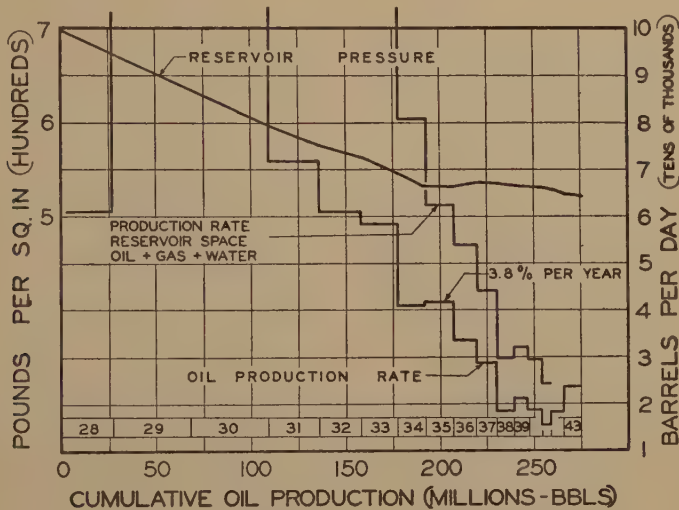


FIG. 11.—YATES PRESSURE-PRODUCTION GRAPH.

sure and oil-production rate, by years, shows also barrels per day reservoir displacement.⁴⁸

It shows that around the 200 million cumulative oil (the year 1935) the oil-production rate has been progressively reduced to about 41,000 bbl. per day, corresponding to 62,000 bbl. per day reservoir displacement. The pressure curve indicates for the year 1935 a balance between withdrawals and water influx.

Continued reduction of oil-production rate brings corresponding reservoir displacement three years later to a rate less than half the 1935 rate. A slight pressure decline corresponding to the lower withdrawal rate would indicate a decreasing water-encroachment factor.

SUMMARY

1. "Degree" of water drive is controlled by both natural conditions (reservoir gas-oil relationships, extent of water body, permeability) and operating conditions (functions of the withdrawal rate).

on the basis of pressure-production curves involves conversion of cumulative oil production from barrels to percentage of ultimate.

4. Examples of a calculated "water-encroachment factor" K_a (barrels of water influx per pound-month per acre-foot of oil reservoir): Schuler (Reynolds), 0.0860; Turkey Creek, 0.0426; Ramsey, 0.0300; East Watchorn, 0.0107; Buckner, 0.0036; Magnolia, 0.0021.

5. After a certain pressure decline, the slope angle of the pressure-production curve decreases in varying degree and in some cases approaches zero, indicating equilibrium between reservoir withdrawal and water influx. The following pressure declines from original pressure correspond to pressure equilibrium and indicate degrees of water drive in the same order indicated by "water-encroachment factor": Schuler (Reynolds), 150 lb. persq.in.; Turkey Creek, 310; Ramsey, 350; East Watchorn, 385 (?).

6. Yearly oil-production rate (percentage of ultimate), which corresponds to

pressure equilibrium, is 11 per cent for Schuler (Reynolds), 11 per cent for Turkey Creek, 8 per cent for Ramsey, 3.5 per cent for East Texas.

7. Midway is a case of artificially created water drive; in order to attain equilibrium in that reservoir, it was recently necessary to increase water injection to a rate approaching the rate of withdrawal of reservoir fluids.

8. Control is exercised by adjustment of production rate, by injection of produced water, by injection of outside water. With proper control, full advantage may be taken of the high recovery efficiency inherent in the water-drive mechanism.

ACKNOWLEDGMENT

The writer expresses appreciation for suggestions of Mr. C. V. Millikan as to form of presentation.

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DISCUSSION

W. A. ENGLISH.*—On the second page of this paper is the statement, "In many California fields, water drive was early recognized as an efficient recovery mechanism." Footnotes give three references, which presumably form the basis for this statement.

I believe that this statement is misleading, for the following two reasons: (1) The references do not in fact cite numerous fields in which water drive has been an efficient recovery mechanism; (2) taken with the adjacent text, they would lead to the belief that the efficiency of water drive was not only recognized by early observers but has in fact been present in the type of pressure maintained, highly effective recovery mechanism, by which possibly twice

* Geologist, Los Angeles, California.

as much oil is recovered as could be expected from gas drive alone. This is not true for any of the larger California fields. We may find out in the next 10 or 20 years how effective water drive can be made under controlled conditions, but we have not found out so far, for the simple reason that the law of capture has reigned supreme, and edge-water encroachment has been so irregular as to be a detriment to large recovery rather than an aid. At the present time thoughts of higher recovery per acre-foot of reservoir take the form of proposals for pressure maintenance by gas injection to keep back the edge water, and getting the oil out by gas circulation or by an enlarging gas cap with gravity drainage. So far as edge water will move up as a regular rising bottom water, so much the better. However, it is generally felt that any pressure grade sufficient to cause a water drive in a reasonable length of time will be too high for the even advance of the water, which is the basic requirement for an efficient water drive.

To go back to the references, they may be summarized as follows:

Reference No. 13 (Barnes and Bowes on the Seal Beach oil field). On reading this paper I find nothing whatever to substantiate the quotation. On the contrary, water encroachment was viewed as an unfortunate mechanism by which a large amount of oil was trapped and made unavailable for future recovery. The words "water drive" or any equivalent wording do not appear in the paper at all. The history of the field to the date of the paper is given as one of rapid development and wide open production until the gas pressure was almost entirely dissipated. There followed rapid water encroachment, but without any noticeable increase in pressure or oil production, the only result being that the wells were drowned out by water. If this is an efficient recovery mechanism, I must revise my ideas of efficiency.

Reference No. 16 (Elwood oil field, by S. G. Dolman): A somewhat better showing is made here, as on page 11 we find the statement, "Due to the extremely low gas-oil ratio of the field and the slow decline in production, it is generally believed that hydrostatic, rather than

gas pressure, is the main cause that forces the oil to the surface." On the other hand, we also find on page 10 the statement, "If all edge wells which are producing an appreciable amount of water were used for gas injection, the ultimate recovery of oil from the field would, in all probability, be greatly increased." This is hardly an endorsement of water drive as a superefficient recovery mechanism.

Reference No. 23 (Wilhelm, Davis and Clark) is a short general paper outlining the various factors in moving oil from the reservoir to borehole, with several California fields cited as examples. The only field cited as producing under water drive is Lompoc, which is not a typical field, the reservoir being a hard, brittle, crushed shale. Other examples are of what is called "delayed water drive." Under this mechanism, after most of the gas has been exhausted and the pressure depleted, there is an edge-water encroachment that gives a short "flush" period just before the water reaches any particular well. Quantitative results of this type of delayed water drive are not given, but Elwood and Mount Poso are cited as fields where it is believed to be quite important and less delayed than in other fields.

G. R. ELLIOTT (author's reply).—Mr. English's comments make a valuable supplement to this paper, which so conspicuously lacks California examples. I agree with Mr. English that the statement he quotes is misleading. The benefits derived from water drive in California are very lightly touched upon in the literature, and apparently little has been done toward operating reservoirs so as to permit full water-drive control.

The following is an additional example of what might be regarded as an early recognition of water encroachment as a beneficial agent: "An interesting condition of the field is the relatively small amount of gas associated with the oil, the migration apparently being primarily due to gravity and the pressure of edge water."*

* V. H. Wilhelm and L. W. Saunders: Report on the Mt. Poso Oil Field. Summary of Operations, California Oil Fields. California State Mining Bureau (Jan. 1927).

A New Technique for Determining the Porosity of Drill Cuttings

BY M. A. WESTBROOK* AND J. F. REDMOND,* MEMBER A.I.M.E.

(Local Fall Meetings, October 1945)

A METHOD is presented for obtaining porosities of consolidated formations from the drill returns. The method provides a means of determining the bulk volume of a large number of particles, such as drill cuttings, by employing a capillary diaphragm for removal of surplus surface liquid from saturated cuttings having pores of capillary size, which reduces the amount of error present in former attempts to determine the porosity of drill cuttings. The method makes it possible to obtain a considerable amount of supplementary data on consolidated formations.

INTRODUCTION

Porosity is a direct measure of the volume of the voids in a formation. It may be used for estimating the permeability of a formation provided that a correlation of these two properties has been obtained from the analysis of cores from the particular formation, and it forms a desirable aid in interpreting electric logs.¹ These useful applications have emphasized the importance of developing a method for determining the porosity of the formations penetrated by a well by some means other than coring, for even in exploration wells it is neither economical nor practical to core all formations. Also, in wells where at the outset the coring program appears comprehensive, it is frequently found that, after certain layers are drilled, more complete information is required for evaluation. Porosity

values, if obtainable, would be of great assistance in such cases.

In soft formations it is usually possible to obtain porosities after drilling with cores taken by side-wall coring devices. In hard consolidated formations, that coring procedure is not always practicable and other methods for determining porosities must be resorted to. A first choice is the examination of drill cuttings, if an analytical procedure is available that is both accurate and reasonably rapid. Such a procedure has been devised and is applicable to sand and limestone cuttings having pores of capillary size. Although improvements can yet be made, it is believed that the new technique is sufficiently well developed to warrant description.

PREPARATION OF SAMPLE

The well samples containing the cuttings representative of the particular intervals are first washed through a No. 6 gauge screen. The cuttings remaining on the screen are large enough to use for the porosity measurements. From the sized sample, the cuttings to be examined are separated from the shale and other extraneous particles. It is recommended that 10 to 15 c.c. of the selected cuttings be used for measurements, although only 4 to 5 c.c. were used to make the comparative tests described later in this article. These cuttings are extracted and dried by the same methods used for preparing core samples for porosity and other measurements.

The separation, which is at present being carried out by hand, is the most tedious

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* Shell Oil Company, Inc., Houston, Texas.

¹ G. E. Archie: The Electrical-resistivity Log as an Aid in Determining some Reservoir Characteristics. *Trans. A.I.M.E.* (1942) 146,

part of the procedure, and possible mechanical or otherwise automatic methods for facilitating the separation are being investigated.

so that the weight of water added may be determined. This weight is converted to volume by knowing the density of the water at the temperature existing at the

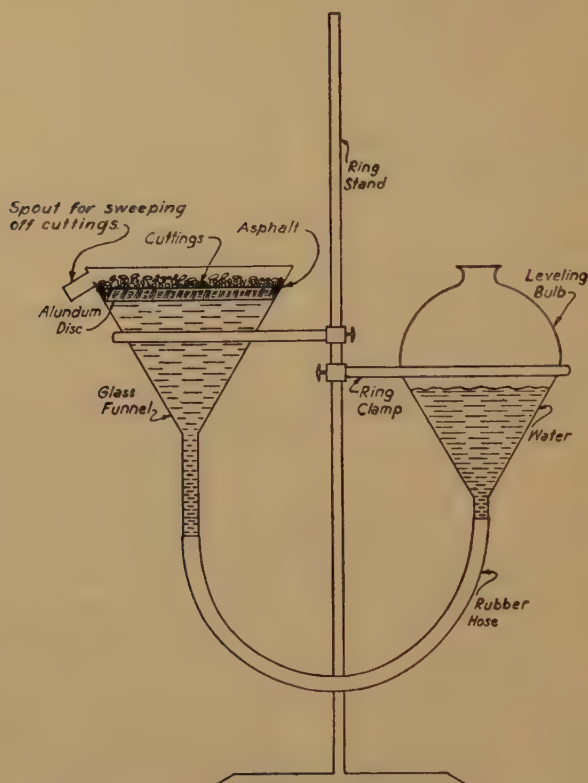


FIG. 1.—APPARATUS USED IN DETERMINATION OF POROSITY OF DRILL CUTTINGS.

DETERMINATION OF GRAIN VOLUME

The clean, dry cuttings are weighed, placed in a weighed and volumetrically calibrated graduate, evacuated for approximately 20 min., and then saturated by allowing water to flow into the evacuated system. The system is next opened to the atmosphere and allowed to stand for 5 to 10 min., so that the water will completely penetrate the pores. Longer times may be required for cuttings having very low permeabilities. Water is added until the graduate is filled to the calibration mark. The graduate and contents are reweighed

time the flask was filled to the calibration mark. The resultant volume subtracted from the flask's calibrated volume equals the volume occupied by the dry grains. This volume is later referred to as grain volume.

DETERMINATION OF BULK VOLUME

After the grain-volume measurements, the saturated cuttings are spread on an alundum (R.A. -98) disk, which is saturated and in contact with a column of water. A typical single-unit arrangement of this capillary diaphragm is shown in Fig. 1. As many diaphragms may be

connected to a common water column as is desired, and any porous material may be used provided it is permeable and has a displacement pressure² to air, when satu-

manner the excess water is removed, leaving each cutting completely saturated, with each pore filled to its surface opening.

Fifteen to 20 min. usually is required for

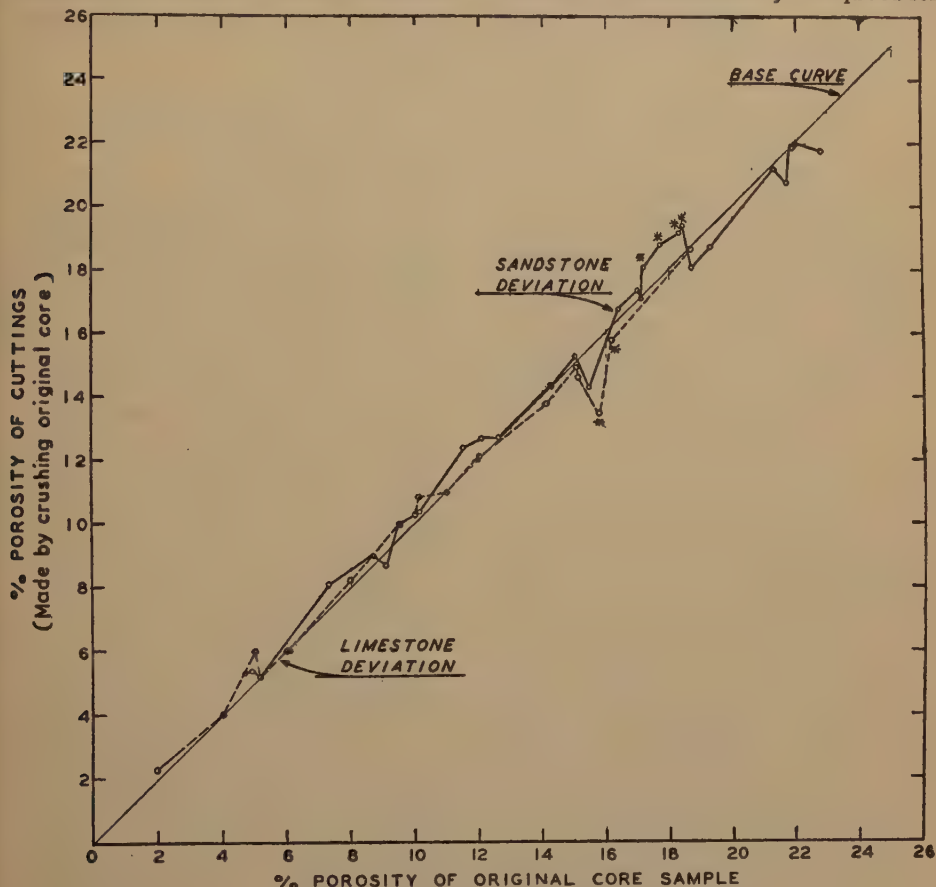


FIG. 2.—COMPARATIVE MEASUREMENTS.

* Anhydrite present in limestone sample and shale present in sandstone sample.

rated with water, equivalent to at least 2 ft. of water.

By lowering the leveling bulb, suction is applied to the water in the diaphragm, which, in turn, pulls the water from the surface of the cuttings by capillary suction. The amount of suction applied to the system must be less than the displacement pressure of the rock analyzed. In this

the diaphragm to remove the excess water from the cuttings. The removal will be facilitated by turning the cuttings occasionally with a glass rod or spatula. Although it is not possible to tell by sight when the excess water has been exactly removed, its complete removal is indicated by the absence of a glistening caused by light reflected from excess water. Complete removal is assured by allowing the cuttings to remain on the diaphragm several minutes after the glisten has disappeared.

² G. L. Hassler and E. Brunner: Measurement of Capillary Pressures in Small Core Samples. *Trans. A.I.M.E.* (1945) 160, 114.

A suction of one foot of water is in most cases considered safe, although it is possible that this suction would exceed the displacement pressure of some types of samples. Should the displacement pressure be exceeded, air would enter the pores and the cuttings would be partly desaturated. If it is desired to determine the maximum suction that may be used with a particular group of samples, check bulk-volume measurements may be made with gradually increasing suctions. When the bulk volume no longer remains constant, but begins to decrease, the limiting suction has been reached.

The capillary diaphragm automatically compensates for water evaporating from the surfaces of permeable cuttings while in place on the diaphragm. For example, when the excess water has been removed from the surfaces of the cuttings, evaporation of water will tend to dry out the cuttings. For desaturation to take place, however, air must enter the pores, which in turn means that the displacement pressure of the rock must first be exceeded. It will be remembered that the column of water in contact with the diaphragm and cuttings is adjusted so that the suction head is less than the displacement pressure. It is, therefore, more difficult for air to enter the cutting than for water to flow in from the diaphragm. Complete saturation of the cutting is thus maintained. This process will be effective unless the cuttings have very low permeabilities. For such cuttings the rate of evaporation from the surfaces may be more rapid than the rate of flow of water through the cutting to replenish the evaporation loss, and these impermeable samples should be covered while on the diaphragm.

The saturated cuttings are next transferred to a calibrated graduate containing sufficient water to cover the sample. The addition of one gram of ammonium nitrate per liter of water will prevent the

adherence of air bubbles to the particles and eliminate foaming at the surface. The bulk volume is equal to the displaced water. The porosity value is then calculated from the formula:

Per cent porosity

$$= \frac{\text{Bulk volume} - \text{grain volume}}{\text{Bulk volume}} \times 100$$

The accuracy of this procedure is demonstrated by the results of a number of comparative measurements plotted in Fig. 2. The results were obtained by first determining the porosity (by a standard core-analysis method) of sandstone and limestone core samples having bulk volumes of 4 to 5 c.c. These pieces were crushed to a particle size comparable with that of the cuttings that would normally be obtained from a well. The porosity of the particle retained on a No. 6 screen was determined by the method described here. The average deviation of the two porosity measurements made on each sample was 3.3 per cent of the porosity.

Although the actual porosity measurement is satisfactory, it is obvious that the results are reliable only if it is certain that the cuttings analyzed are representative of the interval drilled. It is also desirable that the recovered cuttings be as large as possible, and that there be a minimum contamination by cuttings or cavings of shale and other shallower formations. For these reasons, special precautions often must be taken when drilling and sampling. In zones of particular interest, it may be necessary to drill intervals of, say, 2 ft. and to circulate the cuttings from the well before the next interval is drilled. Larger cuttings are recovered by using carefully conditioned drilling muds and increased mud-circulating rates. Reverse circulating drilling methods have also been used to advantage for recovering representative and large cuttings.

An Application of Statistical Methods to Core Analysis Data of Dolomitic Limestone

By A. C. BULNES*

(Tulsa and Fort Worth Meetings, October 1945)

ABSTRACT

THIS paper applies the methods of statistical analysis to the interpretation of core analysis data of dolomitic limestone from the San Andres formation at Wasson and the Clearfork formation at Fullerton.

Probability relationships are shown to connect the porosity and the permeability and the porosity and the fluid saturation. For example, the porosity-permeability relationship expresses the probability that a sample of porosity, f , will or will not be permeable.

The over-all porosity frequency distribution of the reservoir together with the frequency curves of permeability (one for each class interval of porosity) provide a precise basis for computing the weighted average *productive porosity* of the reservoir for any assigned value of the minimum productive permeability.

The probability that the permeability of a core specimen from Fullerton will exceed a given value appears to be dependent on the percentage porosity of the specimen, its void structure type (i.e., porosity in the qualitative sense), and the given value of the permeability. If continuous profiles of void structure type and porosity are available together with the appropriate porosity-probability of permeability plots, the *net pay thickness* may be estimated.

The *Invasion Index* of a well is defined in terms of the porosity and permeability data. This index is suggested as a basis for comparing wells as regards their suitability as fluid-injection wells.

INTRODUCTION

Three problems of importance in the exploitation of limestone reservoirs may be stated as follows:

1. The determination of the productive porosity of the reservoir. The productive porosity is defined as

$$\bar{f} = f_p V_p / V \quad [1]$$

in which V_p is the volume of the reservoir that is sufficiently permeable to oil to give up an appreciable fraction of its original oil in place during the economic life of the reservoir; f_p is the arithmetic mean porosity of the permeable volume V_p , and V is the total volume of the reservoir.

2. The determination of the number of feet of oil-bearing porous rock that will produce at a commercial rate into the well bore; i.e., the net pay thickness.

3. The choice of fluid-injection wells in a secondary recovery program.

The ultimate recovery of the reservoir is proportional to the productive porosity. The productive capacity of the well is proportional to the net pay thickness.

The principal purpose of this paper is to show that the methods of statistical analysis when applied to core analysis data of dolomitic limestones offer a useful approach to the solution of these three problems, as well as others of importance in reservoir engineering. The use of these methods was suggested by the work of Jan Law.¹

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*Shell Oil Company, Incorporated, Midland, Texas.

¹ References are at the end of the paper.

GRAPHICAL REPRESENTATION AND STATISTICAL MEASURES

Where numerous data are to be handled it is necessary to put them into a concise

the class interval rectangles whose altitudes are proportional to the percentage frequencies. The total area of the histogram must equal 100.

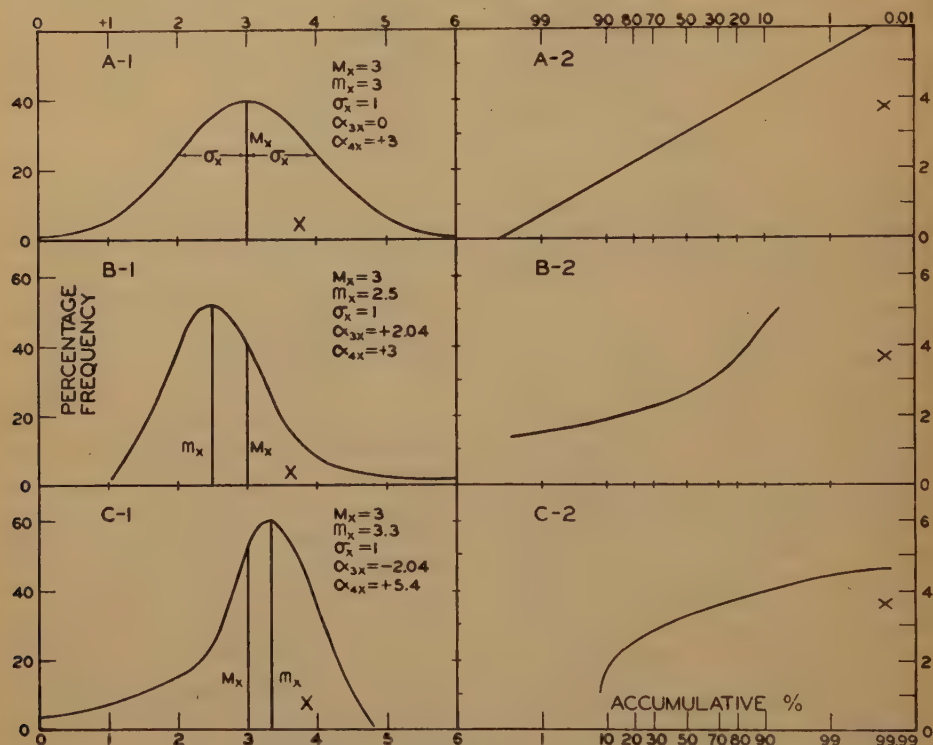


FIG. 1.—EXAMPLES OF FREQUENCY AND CUMULATIVE CURVES.

form that will reveal the essential characteristics of the distribution. The histogram and the cumulative curve are convenient representations of this kind. Suppose, for example, 1000 porosity data are available, the values ranging from 0.5 to 28 per cent. Selecting arbitrarily a class interval of one unit of porosity, the data are divided into 28 classes according to the value of each item. Dividing the number of data in each class interval by 1000 and multiplying by 100 yields the corresponding percentage frequency, or the probability that a single datum will fall in this interval. The histogram is then constructed by erecting on

The cumulative curve is constructed by accumulating successive percentage frequencies, plotting the successive sums against the upper limit of the class interval whose frequency was added last, and connecting the points so obtained by a smooth curve.

A drawback to the use of the histogram arises from the fact that its appearance is influenced by the size of the class interval chosen. If enough data were available so that the class interval could be decreased indefinitely, a unique continuous frequency curve would be approached. The problem is to find the frequency curve underlying

the observed data. Fig. 1 shows three common types of frequency curves and their associated cumulative curves. Appendix A discusses a method by which such curves

of straightening this type of curve, is shown in Fig. 1, A-2. The normal curve is completely defined by M_s , the arithmetic mean value of the distribution, and

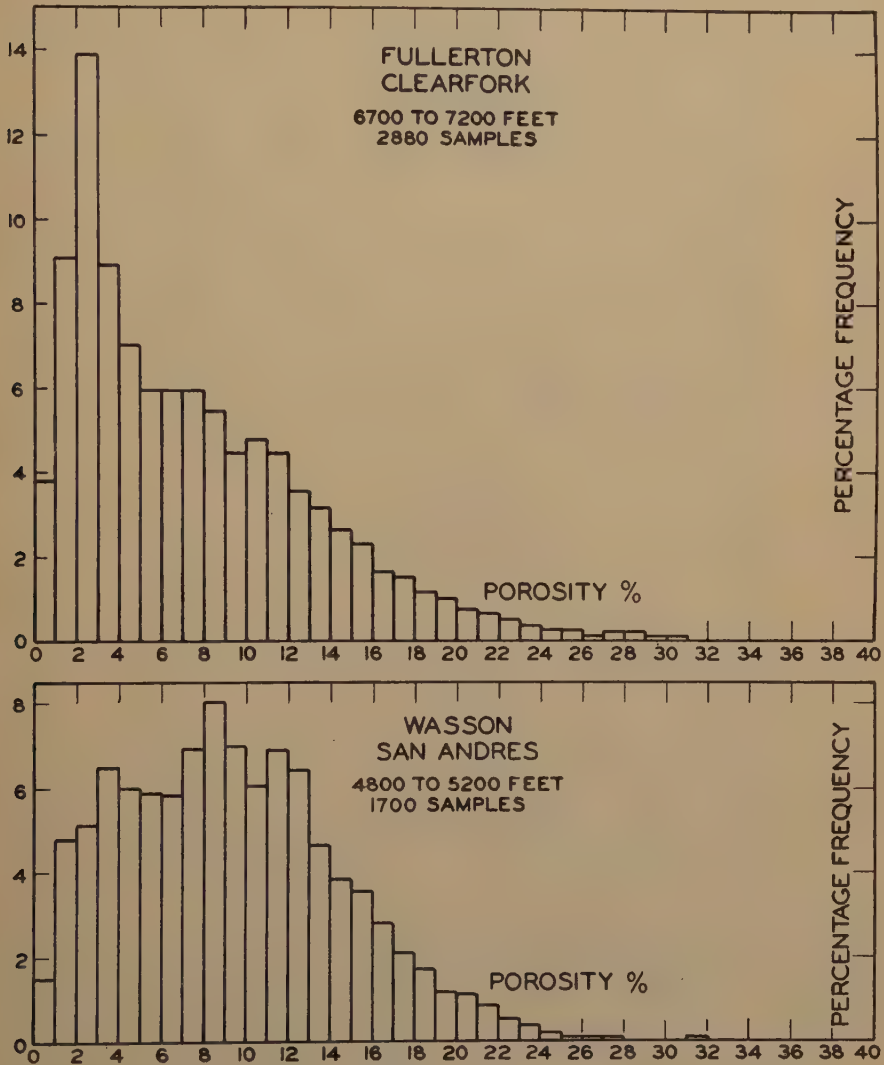


FIG. 2.—POROSITY HISTOGRAMS.

may be fitted to the observed data. The familiar normal, Gaussian, or bell-shaped curve is shown in Fig. 1, A-1; its associated cumulative curve plotted on arithmetic probability paper, which has the property

σ_x , the standard deviation. Departures in shape from the normal are expressed in terms of other parameters, such as α_{3x} , the skewness α_{4x} , a measure of the kurtosis, and so forth. The skewness introduces

asymmetry into the curve (Fig. 1, B-1 and C-1), while the kurtosis determines the peakedness (or flatness, depending on the sign) of the curve (Fig. 1, C-1).

The Fullerton data consisted of the core analyses of 15 wells scattered over the field. Core recoveries were from 50 to 100 per cent, and from 100 to 900 core analyses

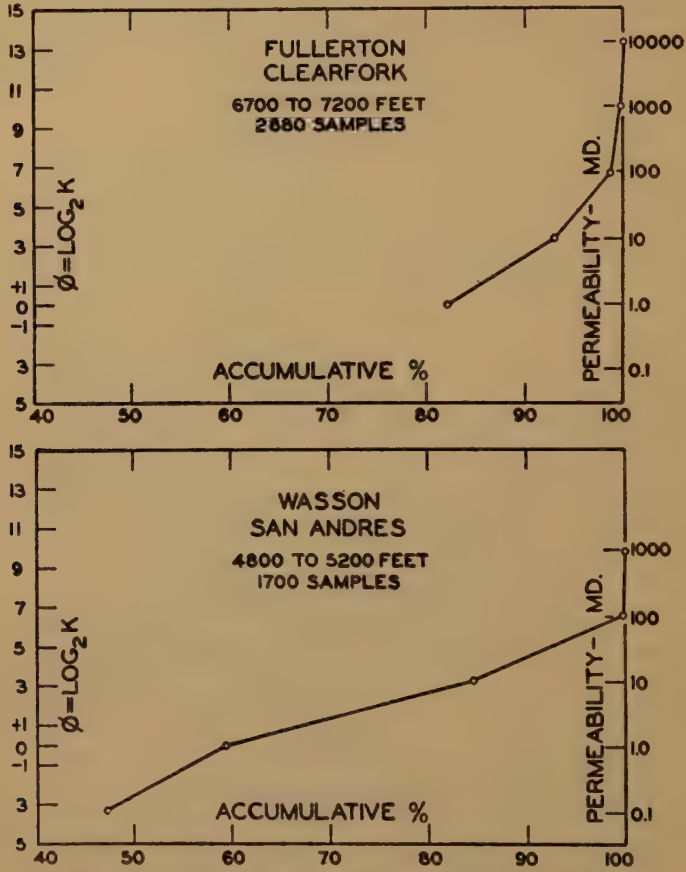


FIG. 3.—CUMULATIVE PHI (PERMEABILITY) PLOTS.

These, and higher parameters, are fundamental properties of the distributions, and their method of computation is given in Appendix A.

SOURCES OF DATA

The data pertained to cores from the San Andres dolomite of Permian age in the Wasson field, Gaines and Yoakum Counties, Texas; and the Clear Fork dolomite of Permian age in the Fullerton field, Andrews County, Texas.

per well were available. Five wells in the central portion of Wasson were selected on the basis of core recovery and number of analyses per well. Recoveries were from 67 to 89 per cent, while 270 to 490 analyses per well were available.

Permeabilities were measured parallel to the bedding planes and the porosities were total. No attempt was made to take into account the absence of data due to incomplete core recovery, or to the fact that only one, or at most three, fragments

were analyzed out of each foot of recovered core. In the absence of any method by which the influence of the absent data could be determined, it was assumed that the

purpose in hand, several were tried. These are illustrated and discussed below.

Simple porosity histograms for Fullerton and Wesson are shown in Fig. 2. Per-

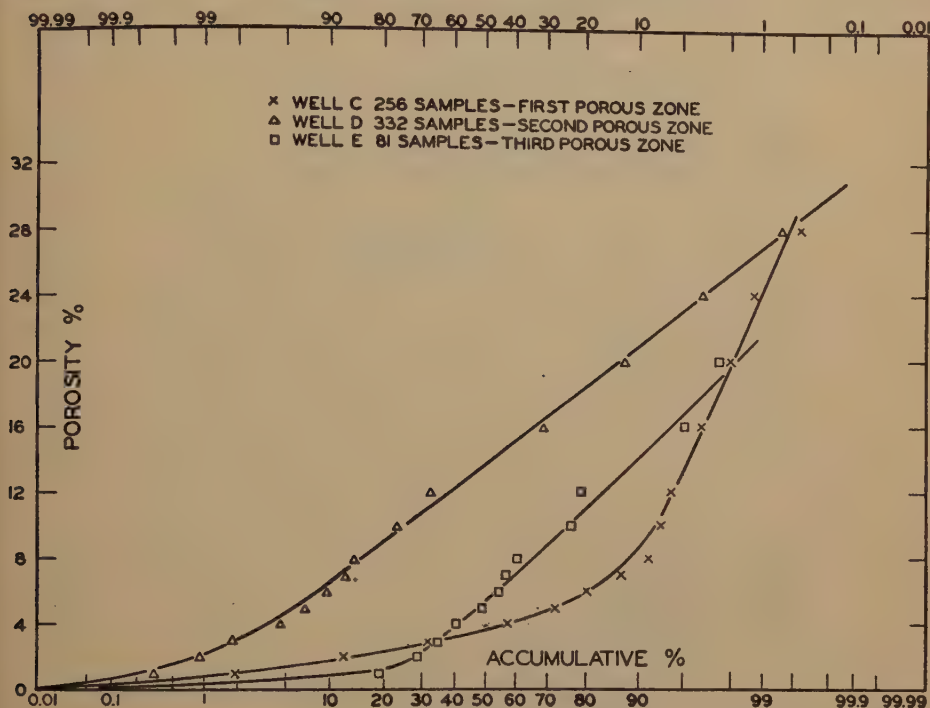


FIG. 4.—FULLERTON—CUMULATIVE POROSITY CURVES.

data available represented the actual vertical distributions. However, any method, whether of statistical analysis or not, that attempts to infer the reservoir from cores is confronted with the same limitations as regards data.

The Wesson wells lie within an area about $\frac{1}{20}$ that of the field, so that it is doubtful whether they represent the field as a whole. The Fullerton wells are widely scattered and presumably are more representative.

PRELIMINARY GRAPHICAL REPRESENTATION OF DATA

Inasmuch as it was not obvious at the start which method of representation would prove most satisfactory for the

meability histograms were not constructed because in both cases an appreciable fraction of the data was outside the range of permeability customarily reported. Instead, cumulative curves showing the percentage of samples with less than a given permeability were prepared (Fig. 3). In each graph the left-hand vertical axis is the ϕ scale² and the right hand is the millidarcy scale. Use of the logarithmic scale $\phi = \log_2 k$ serves to represent conveniently a wide range of permeability, and, in addition, reduces the curvature of the cumulative plot.

CUMULATIVE CURVES OF POROSITY AND PERMEABILITY BY ZONES

Both of the porosity histograms in Fig. 2 are skewed to the right and also

appear to have more than one peak. These conditions may reflect variations in the nature of the distributions between strati-

Fig. 4 shows typical cumulative curves of the porosity distributions in the first, second, and third zones at Fullerton.

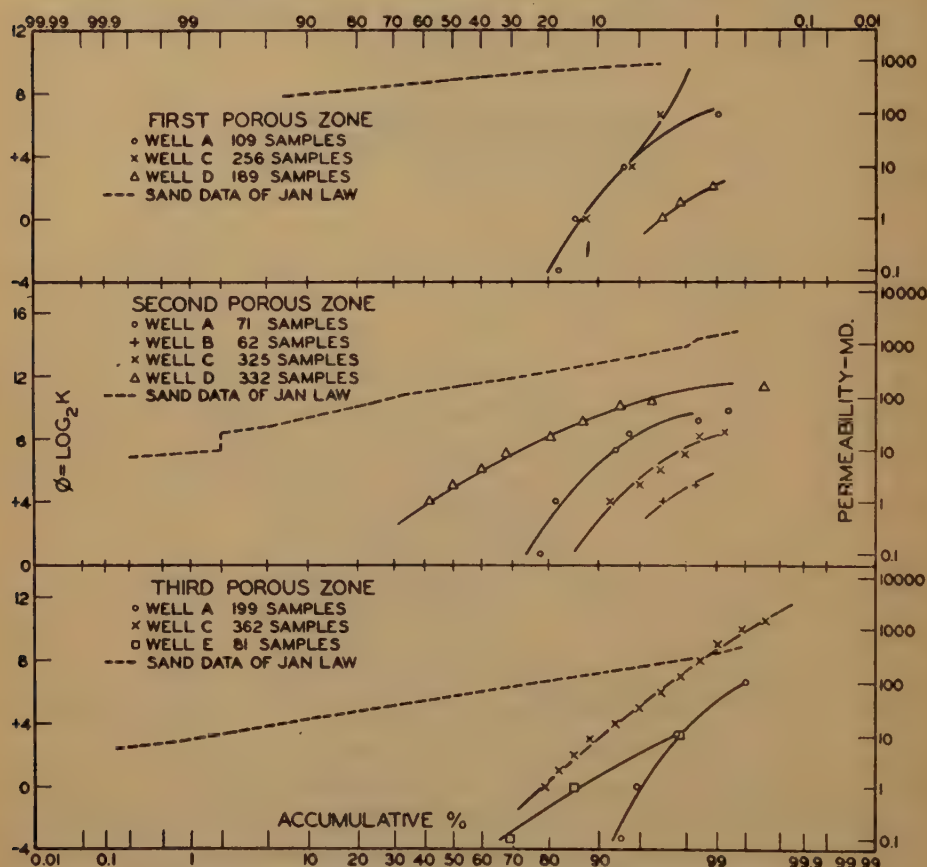


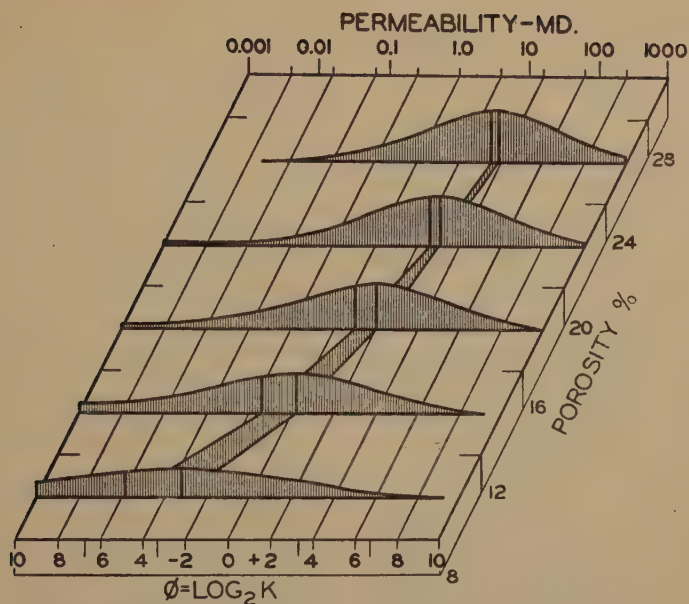
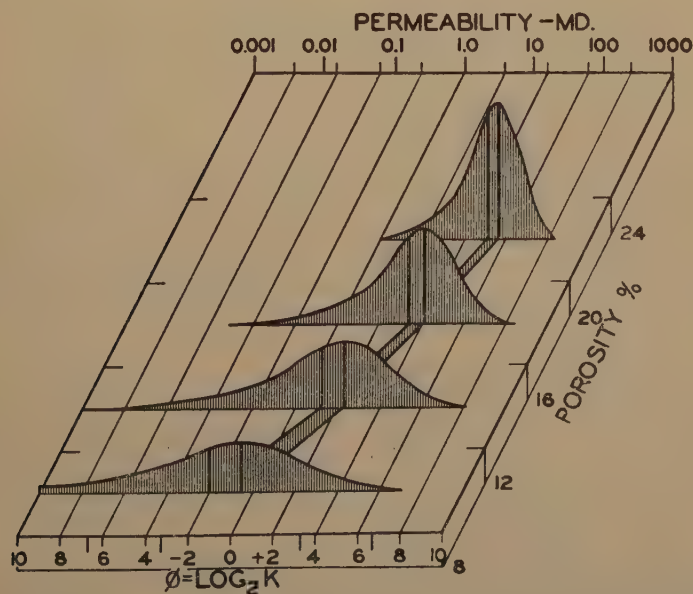
FIG. 5.—FULLERTON—CUMULATIVE PHI (PERMEABILITY) CURVES.

graphic intervals or variations between wells in the same interval, or both.

Three general porous zones are recognized at Fullerton and two at Wasson. Considerable difference was found between the frequency distributions of wells in the same zone at Fullerton, and, in addition, all the cumulative curves showed more or less curvature, indicating departure from the normal form. The Wasson data revealed less difference between wells in the same zone and, in general, the cumulative curves were approximately linear.

Where the curvature of the cumulative curves was not excessive two terms of the Gram-Charlier series (see Appendix A) were found sufficient to fit the frequency histograms satisfactorily.

In Fig. 5 are plotted cumulative permeability data of Fullerton by wells and zones. For comparison the sandstone data of Jan Law¹ are included. As in Fig. 3, the curves cover only a fraction of the distribution. The Wasson permeability data were similarly limited and have been omitted.

FIG. 6.—FULLERTON— Φ (PERMEABILITY) DISTRIBUTIONS AS FUNCTIONS OF POROSITY.FIG. 7.—WASSON— Φ (PERMEABILITY) DISTRIBUTIONS AS FUNCTIONS OF POROSITY.

RELATIONSHIP BETWEEN POROSITY AND FREQUENCY DISTRIBUTION OF PERMEABILITY

The failure of the zonal representation to provide a basis for erecting permeability frequency distributions led to the search for some other scheme by which the influence of the lower permeabilities would be minimized, and this aim was partially accomplished when the data were divided according to porosity. A class interval of four units of porosity was chosen and cumulative plots of the permeabilities in each class were constructed on arithmetic probability paper employing the ϕ scale as in Fig. 3.

Employing the method of Otto³ theoretical distributions, based on two terms of the Gram-Charlier series, were fitted to several of the cumulative curves. The curves for the ranges 0 to 4 per cent and 4 to 8 per cent were too incomplete to fit. The frequency curves are plotted in Figs. 6 and 7. It is evident as regards both the Fullerton and the Wasson data that as the porosity increases the arithmetic mean ϕ and the most probable ϕ tend to coincide; however, although the ϕ standard deviation decreases with increasing porosity, the degree of scattering of the permeabilities in each porosity interval actually increases. In the higher ranges of porosity we may anticipate normal ϕ frequency distributions.

PRODUCTIVE POROSITY OF RESERVOIR

The productive porosity of the reservoir evidently is dependent on the distribution of permeability to oil in the reservoir. In reservoirs where interstitial water saturations are found to increase with decreasing specific permeability, we may anticipate a limiting value of the specific permeability below which the associated water saturation will be high enough to reduce the relative permeability of oil to zero, and zones of this specific permeability or lower, will have zero productive porosity.

On the other hand, in reservoirs where interstitial water saturations are known to be uniformly low (0 to 10 per cent) down to 0.1 md. (or lower) specific permeability, thus constituting no serious obstacle to the movement of oil, the minimum productive permeability of the reservoir will depend chiefly upon how efficiently the low permeable masses are connected by permeable channels to the wells. Each reservoir will present a special problem.

Suppose it has been decided that the minimum productive permeability of a reservoir is 0.1 md., or, in effect, that every core recovered from the pay section with permeability equal to or exceeding 0.1 md. may be counted as productive. Suppose a_i is the (fractional) frequency of occurrence of porosity f_i ; that is, $100a_i$ represents the percentage of the total reservoir volume that has porosity f_i (see, for example, Fig. 2); b_i is the fraction of all cores with porosity f_i whose permeabilities exceed 0.1 md., that is, b_i is the area under the frequency curve and to the right of 0.1 md. (see Figs. 6 and 7.) Then

$$v_p = V \sum_0^{f_M} a_i b_i f_i \quad [2]$$

where v_p is the volume of void space in the permeable rock of the reservoir, V the total volume of the reservoir, and f_M is the maximum porosity occurring in the formation. If V_p is the total volume of the permeable rock (see Eq. 1), then we may also write

$$v_p = f_p V_p \quad [3]$$

Substituting Eq. 3 in Eq. 2 we obtain

$$f_p V_p = V \sum_0^{f_M} a_i b_i f_i \quad [4]$$

and rearranging Eq. 4 we get

$$\sum_0^{f_M} a_i b_i f_i = f_p V_p / V = f \quad [5]$$

the productive porosity of the formation.

Inasmuch as the precise value of the minimum productive permeability is not known for either field, Fig. 8 illustrates the way the productive porosity at Fullerton and Wasson varies with values of the minimum productive permeability ranging from 0 to 10 millidarcys.

In order to give weight to each individual core analysis and since in any case permeability frequency curves for porosities below 8 per cent were lacking, an alternative method was employed for computing the productive porosity values shown in Fig. 8. Table 1 illustrates the method applied to a hypothetical core analysis.

TABLE 1.—*Application of Method for Computing Productive Porosity Values Shown in Fig. 8*

Minimum Productive Permeability Assumed to be 0.1 Md.

Porosity, Per Cent	Permeability, Md.	Productive Porosity, Per Cent
3.8	< 0.1	0.0
4.2	< 0.1	0.0
4.9	0.3	4.9
3.9	< 0.1	0.0
6.5	1.5	6.5
7.8	0.5	7.8
4.9	< 0.1	0.0
8.3	1.3	8.3
8.2	0.3	8.2
12.5	9.0	12.5
14.8	5.3	14.8
		Total 63.0

Total number of cores analyzed = 11; number of permeable cores = 7

$$V_p/V = \frac{31}{63.0/7}$$

and accordingly

$$\bar{p} = \frac{(63.0/7) \times 7}{11} = 5.7 \text{ per cent}^*$$

It should be noted that the degree to which the curves in Fig. 8 approximate to the true productive porosity curves depends upon how closely the data em-

ployed represent the true distribution of porosity and permeability in the reservoirs.

Within the limitations of this assumption it appears, for example, that estimates of reserves at Fullerton based on a minimum productive permeability of 0.1 md. would be approximately $100 \times \frac{4.5 - 2.6}{2.6} = 73$ per cent higher than estimates based on 1 md. At Wasson estimates based on 0.1 md. would be 20 per cent higher.

DIFFERENCE IN TYPE OF VOID STRUCTURE REVEALED BY GRAPHICAL REPRESENTATION OF CORE ANALYSIS DATA

Figs. 6 and 7 reveal a marked difference between the distributions of permeability among cores of the same percentage porosity in Fullerton as compared with Wasson. Not only are the shapes of the frequency curves for the same porosity different, but the way the shapes change with changing porosity in Fig. 6 differs from the manner of change in Fig. 7. Thus, if we follow the line corresponding to 1.0 md. in each figure, we find that for each porosity the fraction of the total area of the frequency curves to the right of 1 md. is, in general, greater at Wasson than at Fullerton; that is, the probability that the permeability of a core from Wasson exceeds 1 md. is evidently greater than the probability that the permeability of a core of the same porosity from Fullerton exceeds this value.

It is reasonable to assume that the observed difference in probability of permeability is a reflection of the difference in the nature of the void structure of the rocks in the two reservoirs. (This difference, as between sandstones and limestones, was discussed in a previous paper.⁴)

Microscopic examination of cores and drill cuttings from Fullerton suggests that the predominant type of void structure in the First zone differs appreciably from the predominant type in the Second

* The value of the productive porosity may be further refined by counting as productive only the cores that, in addition to fulfilling the permeability criterion, possess oil saturations that exceed a preassigned value, and water saturations that are less than some preassigned value.

and Third zones. Percentage porosity-probability plots were prepared, on the assumptions: (1) that the effect of the other types of void structure present in

to be the probability of permeability for the percentage porosity represented. Figs. 9 and 10 contain plots of the percentage porosity-probability of permeability data

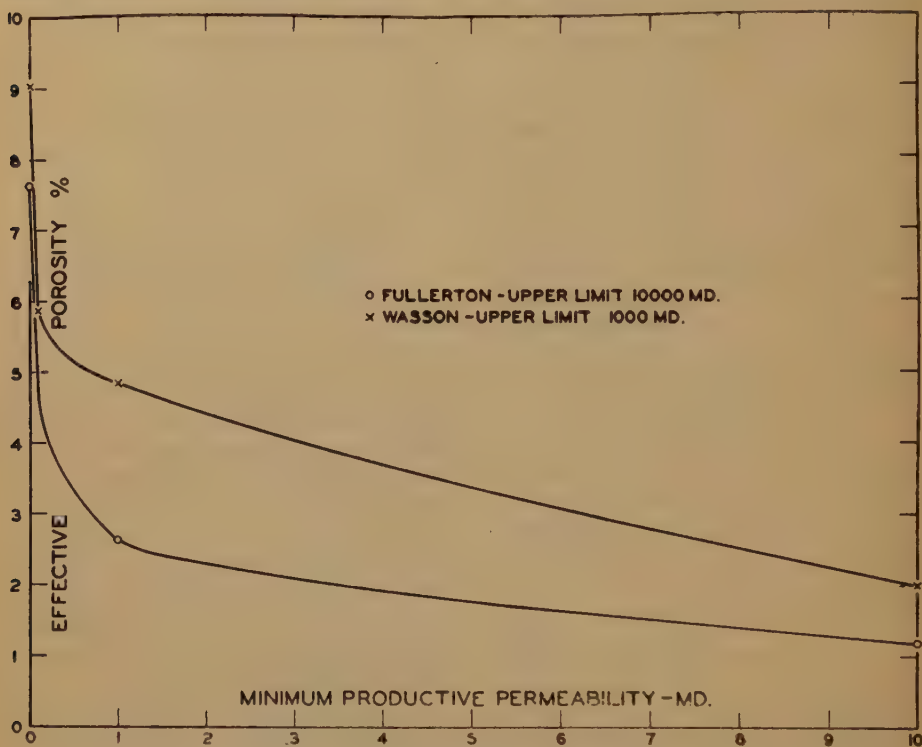


FIG. 8.—PRODUCTIVE POROSITY OF RESERVOIR AS A FUNCTION OF MINIMUM PRODUCTIVE PERMEABILITY.

minor proportions is entirely overshadowed by the effect of the predominant types; and (2) that the difference between the predominant types should reveal itself by a difference in the probability of permeability between cores of the same percentage porosity from the First zone and from the Second and Third zones. After the data of porosity and permeability had been separated into three major groups according to zone of origin, the major groups were further subdivided into smaller groups of equal percentage porosity. The ratio of the number of permeabilities exceeding 1 md. to the total number of permeabilities in each subgroup was taken

for each zone. The fractions to the left of the points shows the number of permeable cores (i.e., permeability greater than 1 md.), divided by the total number of permeable plus impermeable cores in the two or four-unit porosity intervals. The choice of 1 md. as the critical permeability was dictated by convenience only.

The agreement between the data from the two lower zones as compared with the evident difference between them and the data from the First zone lends support to the assumption of the preceding paragraph, that the predominant structure type in the First zone differs materially from that in the Second and Third zones. It

appears that the Second and Third zones require, on the average, a higher porosity to provide a high expectation of permeability than is required by the First zone.

porosity f but belonging to structure type B has a permeability exceeding 1 md., then in general

$$P_a \neq P_b$$

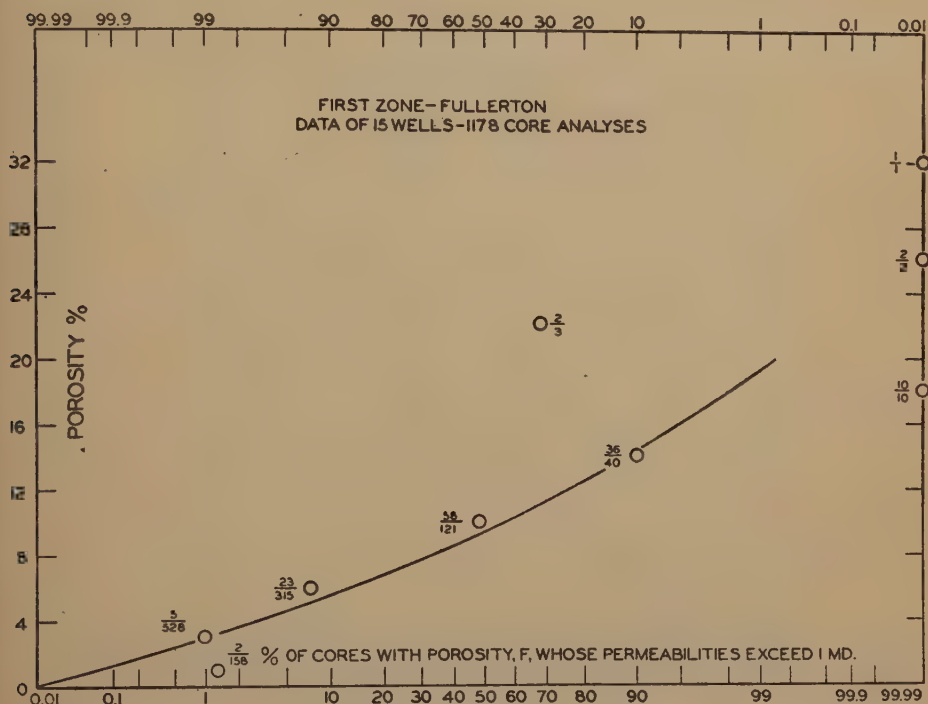


FIG. 9.—FULLERTON—POROSITY-PROBABILITY OF PERMEABILITY RELATIONSHIP.

This suggests that the predominant structure type in the First zone is intermediate while that in the lower zones is intergranular (these two broad types of void structure have been discussed elsewhere⁴), a conclusion borne out by the fact that samples from the First zone frequently display pinpoint to larger intermediate openings, whereas samples from the lower zones are frequently uniformly granular, or crystalline to finely crystalline in texture, with close packing of the particles.

These results suggest the following hypothesis: If P_a is the probability that a sample of percentage porosity f belonging to void-structure type A has a permeability exceeding, say, 1 md.; while P_b is the probability that a sample of percentage

Furthermore, to any sample of a given percentage porosity and of a given type of void structure there corresponds a definite probability that its permeability exceeds or is less than some arbitrarily assigned value. This probability may be expressed as a fraction between 0 and 1, or a percentage between 0 and 100, and if the data of porosity and probability pertaining to all members of the void-structure type are plotted, a convenient graphical representation is obtained of the unique porosity-probability of permeability relationship that characterizes the given void-structure type. For each type of void structure there exists a minimum percentage porosity below which all cores exhibit less than the preassigned critical

permeability, while at the other extreme there exists a maximum percentage porosity above which *all* cores exceed the critical permeability. Consequently, the net frac-

cuttings from the same depth as the cores revealed under the microscope a predominantly intermediate void structure (Fig. 9), or a chiefly intergranular void

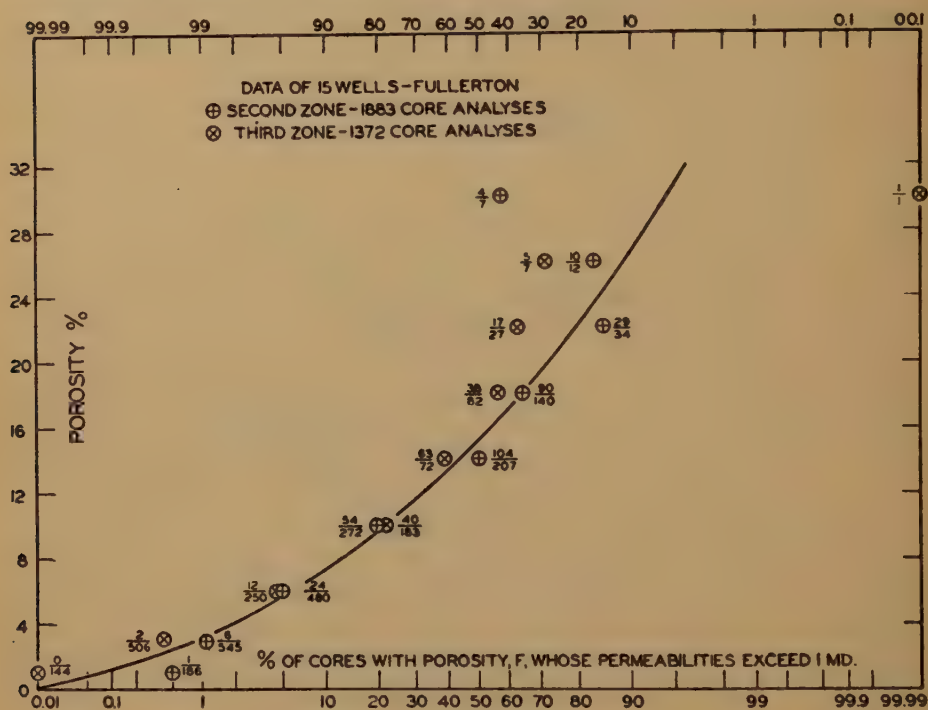


FIG. 10.—FULLERTON—POROSITY-PROBABILITY OF PERMEABILITY RELATIONSHIP.

tion of a gross interval composed of one void-structure type and one percentage porosity will be 0, 1, or some value between 0 and 1, depending, respectively, on whether the percentage porosity is below the minimum, above the maximum, or in between.

ESTIMATION OF NET PAY THICKNESS

The hypothesis outlined in the preceding section suggests a means for determining the net pay thickness when only the percentage-porosity and the void-structure profiles of the producing section are known. The illustration in Table 2 is based on core data from a well at Fullerton. Column 4 shows whether or not drill

structure (Fig. 10). It was assumed that 1 md. or more permeability was productive, while less than 1 md. permeability was assumed to be nonproductive.

The sum of column 6 shows the total net pay interval as determined by the statistical method employing the porosity data and the curves of Figs. 9 and 10 only. The sum of column 8 shows the net interval based on permeabilities measured once per each one-foot interval recovered. The agreement between the sums is good considering that a gross recovered section of only 27 ft. (chosen because it included the region of transition between the First and Second porous zones) is involved. If applied to a longer interval and employ-

TABLE 2.—*Estimation of Net Pay Thickness*

1	2	3	4	5	6	7	8
Depth, Ft.	Gross Interval, Ft.	Porosity, Per Cent	Type of Void Structure	Fractional Probability of Per- meability	Net Interval, Ft.	Actual Measured Permeability, Md.	Net Interval, Ft.
6935-36	1	4.9	Fig. 9	0.07	0.07	0.6	0.0
36-37	1	4.2	Fig. 9	0.04	0.04	0.3	0.0
37-38	1	1.3	Fig. 9	0.00	0.00	0.0	0.0
38-39	1	14.8	Fig. 9	0.92	0.92	8.6	1.0
39-40	1	9.9	Fig. 9	0.56	0.56	2.7	1.0
40-41	1	6.8	Fig. 9	0.20	0.20	0.7	0.0
41-42	1	5.3	Fig. 9	0.08	0.08	0.2	0.0
42-43	1	9.7	Fig. 9	0.53	0.53	10.0	1.0
43-44	1	8.3	Fig. 9	0.40	0.40	1.3	1.0
50-51	1	7.4	Fig. 9	0.26	0.26	0.8	0.0
51-52	1	3.0	Fig. 9	0.01	0.01	0.0	0.0
52-53	1	7.5	Fig. 10	0.12	0.12	0.0	0.0
53-54	1	7.1	Fig. 10	0.10	0.10	0.0	0.0
54-55	1	4.9	Fig. 10	0.03	0.03	0.0	0.0
56-57	1	8.3	Fig. 10	0.15	0.15	1.0	1.0
57-58	1	11.0	Fig. 10	0.29	0.29	0.0	0.0
58-59	1	8.7	Fig. 10	0.17	0.17	0.0	0.0
59-60	1	8.8	Fig. 10	0.18	0.18	0.0	0.0
63-64	1	16.5	Fig. 10	0.58	0.58	1.1	1.0
64-65	1	15.2	Fig. 10	0.53	0.53	1.3	1.0
73-74	1	9.4	Fig. 10	0.20	0.20	0.7	0.0
75-76	1	3.0	Fig. 9	0.01	0.01	0.8	0.0
76-77	1	3.6	Fig. 9	0.02	0.02	0.5	0.0
77-78	1	14.8	Fig. 10	0.50	0.50	0.0	0.0
78-79	1	4.3	Fig. 10	0.03	0.03	0.0	0.0
79-80	1	4.5	Fig. 10	0.03	0.03	0.0	0.0
81-82	1	4.3	Fig. 10	0.03	0.03	0.0	0.0
	27				6.04		7.0

ing curves similar to Figs. 9 and 10 but based on more careful separation of the void-structure types, the method would be expected to lead to a result in closer agreement with the determination of net pay based on observed permeabilities.

The validity of the preceding method cannot be established *a priori*, and its determination must await the results of numerous applications of the method to wells in which a fairly accurate knowledge of net pay exists in advance. If the method is established as trustworthy, the procedure of Westbrook and Redmond⁶ for determining the porosity of drill cuttings will provide a convenient means for obtaining the necessary continuous porosity profile without the aid of coring.

APPLICATION OF STATISTICAL METHODS TO DATA OF FLUID SATURATION

Fig. 11 illustrates the application of statistical methods to residual water saturations in cores from a well at Fullerton

that was cored with oil a recovery of 88 per cent being obtained.

If we may assume that the residual water saturations represent the original interstitial saturations, then it appears that for porosities down to the range 2 to 4 per cent the predominant saturation lies between 0 and 30 per cent, while below 2 per cent porosity any saturation between 20 and 90 per cent is approximately equally probable.*

Data on residual oil saturation also were readily and precisely summarized by the use of statistical methods.

THE INVASION INDEX

In planning a fluid-injection program for reservoir-pressure maintenance it is important to have a quantitative standard

* Preliminary results indicate that for each void structure type a unique relationship exists, analogous to the porosity-probability of permeability function, connecting the percentage porosity and the probability that the residual water saturation exceeds, or is less than, a preassigned value.

by means of which wells may be compared with one another as regards their suitability as injection wells.

The following expression, which is called

where k and f indicate the mean permeabilities and porosities, respectively, of each foot (or a shorter constant interval, depending on the frequency of analysis

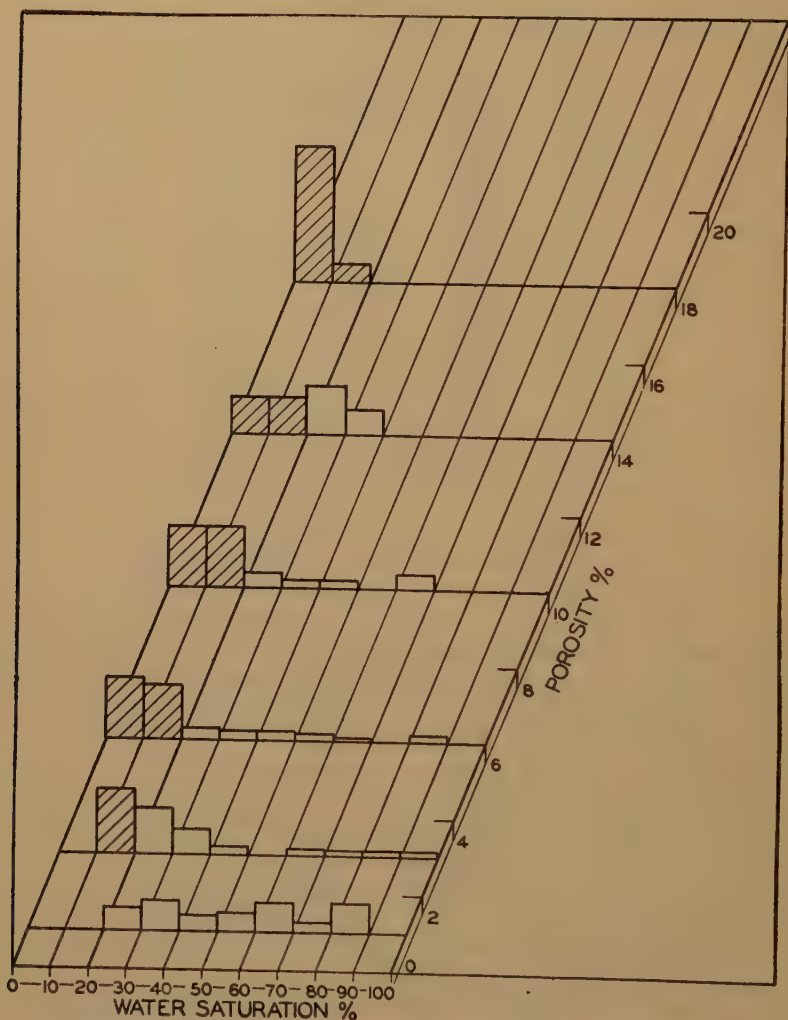


FIG. 11.—FULLERTON—DISTRIBUTION OF RESIDUAL WATER SATURATION AS A FUNCTION OF POROSITY.

the Invasion Index, is an attempt to define such a standard in terms of the core data of porosity and permeability from the individual wells:

$$I = \frac{f_n(k_1 + k_2 + \dots + k_n)}{k_n(f_1 + f_2 + \dots + f_n)}$$

of the cores), and k_n is the maximum permeability and f_n the corresponding porosity (not necessarily the maximum porosity).

Where Darcy's law applies in its entirety, and where the fluids are of the same

viscosity and the displacement is independent of any shape factor, I is the invasion, expressed as the ratio of the volume of displacing fluid to the total original volume of displaceable reservoir fluid, for the instant that the displacing fluid first appears at the output well. For the volume of displacing fluid in any layer i at this instant is to the volume in layer n (the most permeable layer) as k_i is to k_n , while the original volume of displaceable fluid in i is to the original volume in n as f_i is to f_n , from which it follows that the sums of these ratios are proportional, respectively, to the total volume of displacing fluid that has been injected and the total original volume of displaceable fluid.

For an ideally uniform reservoir—that is, one in which the permeabilities and porosities of all layers are equal— I is unity. Variations in permeability, or porosity, reduce the value of I . The presence of a few thin streaks, highly permeable by comparison with the other layers, may reduce drastically the value of I . For example, data from a well at Fullerton, selected on the basis of high core recovery, yielded a value for I of 0.027. (Cores with permeabilities less than 0.1 md. were assigned zero permeability and zero porosity in the expression of I .) The maximum permeability was 570 md. and the corresponding porosity 12.2 per cent. Eliminating these terms from I and replacing them, as coefficients outside the parentheses in the numerator and denominator, with the next highest permeability, 69 md., and the corresponding porosity, 10.8 per cent, increased the value of I to 0.113, or nearly fourfold. In practice this increase in uniformity could be obtained by setting a packer over the permeable streak, or closing it off by some other suitable means, and thereby effectively eliminating it from the productive profile of the well.

CONCLUSIONS

It appears that the data of core analysis of dolomitic limestones lend themselves readily to statistical manipulations. The various concise forms in which the results may be cast give a new aspect to familiar data and thereby suggest new and fruitful interpretations which otherwise would be overlooked; for it is the chief merit of statistical analysis that its use brings out clearly, in the form of condensed numerical expressions, important characteristics of an assemblage of data that are not apparent to an ordinary inspection.

The foregoing results are sufficiently encouraging to suggest that the data of relative permeability, of capillarity and of the electrical properties of the rock also may respond favorably to the application of statistical methods. It is not inconceivable that all the fundamental reservoir factors of the individual core may be interrelated by simple statistical relationships.

APPENDIX A

General references for this section are Fisher⁶ and Wilks.⁷

The Gram-Charlier series was found satisfactory for fitting the porosity and permeability distributions, and was employed in the form given below.

If the empirical probability function $F(x)$ is defined as

$$\Sigma F(x) = 1$$

where x is the distance from the assumed origin, the Gram-Charlier representation of $F(x)$ is

$$F(z) = \frac{1}{\sigma} \{ b_0 \phi_0(z) + b_1 \phi_1(z) + \cdots + b_n \phi_n(z) \}$$

where

$$z = \frac{x - M}{\sigma}$$

$$\phi_0(z) = \frac{e^{-\frac{z^2}{2}}}{\sqrt{2\pi}}$$

and ϕ_1, \dots, ϕ_n are the first and higher derivatives of ϕ_0 with respect to z ; and the b 's are constant coefficients.

For purposes of computation, the arithmetic mean value is defined by

$$M = \Sigma xF(x)$$

and the standard deviation by

$$\sigma^2 = \Sigma (x - M)^2 F(x)$$

The coefficients may be computed as follows:

$$b_0 = \Sigma F(x) = 1$$

$$b_1 = \frac{\Sigma xF(x) - M}{\sigma} = 0$$

$$b_2 = \frac{\Sigma (x - M)^2 F(x) - \sigma^2}{2\sigma^2} = 0$$

$$b_3 = - \left\{ \frac{\Sigma x^3 F(x) - 3M \Sigma x^2 F(x) + 2M^3}{3! \sigma^3} \right\}$$

$$b_4 = \left\{ \frac{\Sigma x^4 F(x) - 4M \Sigma x^3 F(x) - 3(\Sigma x^2 F(x))^2 + 12M^2 \Sigma x^2 F(x) - 6M^4}{4! \sigma^4} \right\}$$

Higher coefficients may be obtained from the general equation:

$$b_n = \frac{(-1)^n \int_{-\infty}^{\infty} F(z) H_n(z) dz}{n!}$$

where $H_n(z)$ is the n th Hermitian polynomial of z .

The n th moment of the distribution, expressed in terms of the observed data is

$$m_n = \Sigma x^n F(x)$$

where, as above, x is the distance from the assumed origin. It is computed by multiplying the observed frequency $F(x)$ of the class x by the n th power of x and adding the products.

A common expression for the skewness in terms of the moments is

$$\alpha_{3z} = \frac{m_3 - 3m_1m_2 + 2m_1^3}{\sigma^3} = -3!b_3$$

It is equal to zero in the normal distribution.

The excess, or kurtosis, may be expressed by

$$\begin{aligned} E &= \alpha_{4z} - 3 \\ &= \frac{m_4 - 4m_1m_3 + 6m_1^2m_2 - 3m_1^4}{\sigma^4} - 3 \\ &= 4!b_4 \end{aligned}$$

In the normal curve $\alpha_{4z} = 3$ and, therefore, $E = 0$.

Fisher⁶ provides detailed examples of the application of the Gram-Charlier series.

ACKNOWLEDGMENTS

The author wishes to thank the Shell Oil Company, Inc., for permission to publish this paper, and the Phillips Petroleum Co. for the use of some of their core data. Particular thanks are due to Mr. W. Hurst and Mr. R. E. L. Taylor, of the

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DISCUSSION

(Brad Mills presiding)

E. R. BROWNSCOMBE.*—Did I understand correctly that a large percentage of the samples had less than one millidarcy permeability?

* Atlantic Refining Co., Dallas, Texas.

A. C. BULNES (author's reply).—Yes, 82 per cent at Fullerton and 60 per cent at Wasson.

E. R. BROWNSCOMBE.—Does this mean that a method should be developed to get records of permeability below one millidarcy?

A. C. BULNES.—I think it would be a good idea, because in some formations, such as the Clearfork at Fullerton and in most of the Ellenburger fields in West Texas, there is some evidence that significant production is coming from the low permeable zones. Furthermore, such data would serve to round out our picture of the statistical relationship between porosity and permeability in the low ranges of porosity in which, incidentally, lie most of the cores recovered from the deeper limestone formations. Providing sufficient surface is exposed to production, it is possible to secure commercial production from very low permeable rock. I think it would be a good idea to lower the limit from 0.1 md. to 0.01 md. at least.

R. W. TESCH.*—Were the entire producing sections cored in both fields?

A. C. BULNES.—Not in all cases. I should say about half the wells in both fields were cored through the entire pay section. At Wasson, some got the top only and others the lower porous zone only.

E. G. TROSTEL.†—Is there a relationship between porosity and permeability in the cores? What kind of a correlation would you need to plot these data against each other? It would look as though you arrived sufficiently close to it—the one on porosity and permeability. Instead of going through and taking the arithmetical average, why could you not simply look at the original data?

A. C. BULNES.—There is a statistical relationship between the porosity and the permeability. It expresses the chance that the permeability of a core of percentage porosity

f exceeds, say, 0.1 md. This chance is influenced by the nature of the void structure of the sample as well as the percentage porosity.

To obtain points for the graphical relationship between minimum productive permeability and productive porosity (Fig. 8) I simply added the porosities of all cores that exceeded a particular permeability and divided the sum of the total number of permeable and impermeable samples with porosity f . This ratio gave the productive porosity associated with the particular permeability, and hence, one point for the graph. Other points were computed similarly. The calculation is simple. Cores could have been eliminated whose water saturations were too high or oil saturation too low, for further refinement.

L. L. BAKER.*—Did I understand you to say that anything at Fullerton with more than 3 per cent porosity had a good chance of being permeable? Do you extend interpretation of this chance to the estimation of net pay formation thickness?

A. C. BULNES.—Speaking roughly, the maximum chance that a core from Fullerton with 4 per cent or less porosity will exceed 1 md. is not greater, probably, than 1 in 100. However, above about 7 per cent the chance for permeability is equal to or better than 1 in 10. (See Figs. 8 and 9, added since the discussion in Fort Worth.)

The statistical relationship may be employed to estimate net pay formation thickness (see new section added since meeting).

PAUL WEAVER.†—In the low permeable zones, do you think it is actually physically possible for oil and water to coexist, or do you think there is still some reason to say that only water is present?

A. C. BULNES.—In some limestone fields, it may be that the low permeable zones are entirely water-bearing. In other fields, for example Wasson, the residual water saturations are predominantly lower than 20 per cent down to the lowest porosities recovered (less than 1 per cent). At Fullerton (see Fig. 11) one well showed the predominant saturations to be less than 30 per cent down to 2 per cent,

* Texas Pacific Coal and Oil Co., Ft. Worth, Texas.

† De Golyer and MacNaughton, Dallas, Texas.

* Core Laboratoires, Inc., Dallas, Texas.

† Gulf Oil Corporation, Houston, Texas.

while below 2 per cent there appeared to be no particular bias toward any saturation between 20 and 90 per cent. Furthermore, the average residual oil saturation of cores of less than 0.1 md. at Wasson was found to be about 28 per cent, and at Fullerton 21 per cent. Evidently, oil and water coexist in the low permeable zones in these two fields, with the water saturations moderate in value.

PAUL WEAVER.—It would have a bearing on whether it is limestone or source rocks. If all the oil has migrated into the rock, it would seem that prior occupancy by water would not let oil in volume get in. If you feel from these results that the very low permeabilities afford a substantial contribution to production, it would seem to me that it is too much to expect a strong probability that the oil was contemporaneous with the water.

A. C. BULNES.—In general, the rate of production from the low permeable zones will depend on: (1) the degree of interference of the connate water present, and (2) the area of surface exposed by the dense zones to permeable channels having access to the well bore.

CHARLES PATTON.*—Would you give your opinion of the minimum productive permeability in the Fullerton field?

* Magnolia Petroleum Co., Dallas, Texas.

A. C. BULNES.—I have not formed a firm opinion on that. This study was not designed to establish this point, inasmuch as a separate problem is involved. I said, if one millidarcy were assumed to be the true minimum productive permeability, whereas in reality the value is 0.1 md., the resultant estimate of ultimate recovery would be 70 per cent in error.

It is possible that the correct minimum productive permeability may be estimated by comparing computed volumetric ultimate recoveries based on various assumed values of the minimum productive permeability with an estimate arrived at by an independent reliable method.

I am inclined to favor about 0.1 md. for both Wasson and Fullerton. However, this is strictly a personal opinion.

N. G. FITZ GERALD.*—To what extent are your conclusions influenced by the percentage of core recovery?

A. C. BULNES.—No more nor less than conclusions arrived at by any other method that employs core data as a basis. However, new, improved methods of coring are increasing the percentage of core recovery, and this objection should gradually be removed.

* Abilene, Texas.

Some Practical Aspects of Radioactivity Well Logging

BY WARREN J. JACKSON,* MEMBER A.I.M.E. AND JOHN L. P. CAMPBELL*

(Chicago Meeting, February 1946)

ABSTRACT

AUTOMATIC recording of the radioactivity of the earth's formations provides a log of relative intensities that, if properly interpreted, can be applied to oil-field engineering. Production, engineering, and geological departments regard the radioactivity log as a forward step in the securing of more conclusive information for successful well completions. Explanations of the technique, together with some of the problems to which radioactivity logging have been applied, are presented in this paper.

INTRODUCTION

Those responsible for the completion of new oil and gas wells, or with planning workover operations on old wells, have followed closely the development of radioactivity well logging because they are interested in reducing the number of unknowns that usually are present in such work. Many operators have made use of the log, or are acquainted with at least one of the applications, but it is unlikely that any one operator is familiar with all of the many applications that are possible.

The purpose of this paper is to present a representative example of each of the many applications, wherever the information has been released by an operator, and to illustrate by hypothetical examples other applications, releases for which have not been given. In this way, it is hoped that a better understanding of the scope of this new engineering tool may be obtained.

Although the literature contains many

references that describe in detail the theory, development, and application of radioactivity well logging, a brief discussion of the technique may be helpful to those who are investigating the subject for the first time.

All rocks contain radioactive material in varying concentrations. In general, shales contain relatively more radioactive material than sandstones or limestones. These radioactive materials disintegrate with time into other materials of lower atomic weight, and in that process of disintegration the rocks are emitting many rays, the most penetrating of which is the gamma ray. The intensity of emission of the gamma ray is proportional to the quantities of radioactive materials present. A higher rate of emission would be observed, therefore, opposite a shale than opposite a sandstone or limestone.

Since measurable intensities of gamma rays are capable of penetrating as many as five concentric strings of casing, and as the gamma-ray intensity is relative to the formations, the measurements of variations in gamma-ray intensities offer a means of identifying cased-off formations in their proper stratigraphic sequence.

THE GAMMA-RAY CURVE

The measurement of gamma-ray intensities is accomplished by means of an ionization chamber that consists of a heavy cylinder, about 3 ft. long, that contains two insulated electrodes and is filled with an inert gas under high pressure. Under normal conditions no current will flow through the gas when an electrical potential is set up between the electrodes, but when

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* The Lane-Wells Company, Dallas, Texas.

the chamber is exposed to gamma-ray radiation the gas becomes partly ionized and permits the flow of a very small current between the electrodes. The amount of this current varies directly as the ionization, which, in turn, is proportional to the intensity of the gamma rays acting upon the gas.

An amplifier in the instrument case with the ionization chamber amplifies these small variations in current, and transmits them, through the logging cable of the hoist truck, to the instrument truck. The instrument truck contains additional amplifiers, sensitivity controls, and an automatic pen-type recorder that translate down-the-hole signals into variations in amplitude of a curve that is developed on a strip chart moving in synchronization with the instrument. The curve that records the variation in intensity of the gamma-ray emissions of earth material with depth is called a gamma-ray curve.

Because both sandstones and limestones are recorded as minimum values on the gamma-ray curve, it is almost impossible to distinguish between the two by inspection of the curve alone. To enable positive identification of sandstone and limestone, the neutron curve was developed to complement the gamma-ray curve.

THE NEUTRON CURVE

The neutron curve is obtained through the use of an instrument identical to that previously described, but with the addition of a neutron source appropriately shielded from the ionization chamber. Neutrons from this source bombard the earth material immediately surrounding the well bore, and the effect of this bombardment is measured by the ionization chamber. The character of the recorded measurement is such that if the formation contains hydrogen, which is commonly associated with well fluids, the intensity of the recorded curve is considerably less than if the formation were dense and devoid of fluid.

Thus, when a minimum value on the gamma-ray curve is interpreted as either sandstone or limestone, a minimum value on the neutron curve would indicate sandstone, and a maximum value would indicate a dense limestone. This responsiveness of the neutron curve to the presence of fluid also makes it possible to identify zones of porosity in limestone or chalk sections. It should be explained that, although the neutron curve is responsive to well fluids, it cannot distinguish between them, and therefore cannot be used to determine the type of fluid in a subsurface rock.

BOTTOM-WATER SHUTOFF

Fig. 1 illustrates a typical "bottom-water" plug-back operation in the Conroe field, Montgomery County, Texas. The original completion was based on coring information, and the casing was set above the producing stratum, with a liner set through the pay zone. Water production had increased to 30 per cent when plugging back operations began.

A gamma-ray log was run to select a more favorable zone, and the results are shown in Fig. 1. The casing seat is indicated clearly on the log by a shift to the left. The top of the liner also is shown by contrast, in the dampening effect of two strings, versus one string, of pipe, indicated by a shift to the right at the point where only one string of pipe was set.

The liner was perforated opposite the shale at a depth of 5058 to 5064 ft., and a satisfactory squeeze job was obtained, following which the well was perforated for production from 5043 to 5048 feet.

On a production test the well flowed at a daily rate of 100.06 bbl. of pipe-line oil on $\frac{1}{8}$ -in. choke, with a tubing pressure of 500 lb. and a gas-oil ratio of 538 cu. ft. per barrel.

PLUGGING BACK TO UPPER PAY

Before the introduction of electric logging, a log of a well usually consisted of a

composite record constructed from cores, cuttings, and the driller's interpretation of the formations. The accuracy of such a log was affected by lost cores, careless

the lower Christmas-tree flange. The core record, corrected to the same measurements of the lower Christmas-tree flange, showed good correlation agreement. The gamma-

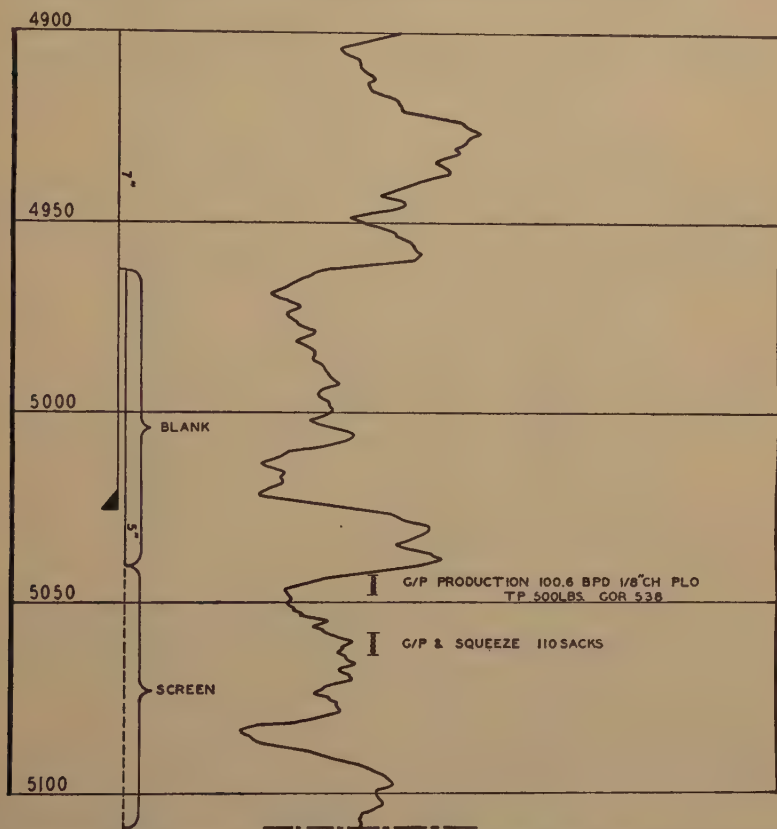


FIG. 1.—TYPICAL APPLICATION OF GAMMA-RAY LOG IN BOTTOM-WATER SHUTOFF, CONROE FIELD, TEXAS.

sampling and measurements, and frequently by weather conditions. Fig. 2 illustrates such a log. This well recently became depleted to a point where abandonment or recompletion had to be considered. From an analysis of the condition of the well it appeared advisable to run a gamma-ray log because subsequent wells had cored, and logged, a gas sand that was not reported on the log of this well. Because gas was needed for local operations, the gamma-ray log was run upward from 6150 to 5000 ft. with a permanent zero point at

ray curve logged a sandstone stratum at a depth of 6050 ft., a point at which no cores were reported.

It should be noted, also, that although the zone from 6035 to 6068 was cored, the reported recovery of only the bottom 2 ft. was actually below the stratum found by the gamma-ray log. The sandstones and shale of the section are so unconsolidated that the cores probably were washed out before reaching the surface.

The well was completed in 1935, and since that time it has been produced from

the gun perforations shown on the graph to the right of the core record. With the gamma-ray log information at hand, the operator squeezed off the old perforations

operators discontinued the well on production and converted it to an injection well for the disposal of salt water in the upper nonproductive zones. A gamma-ray log

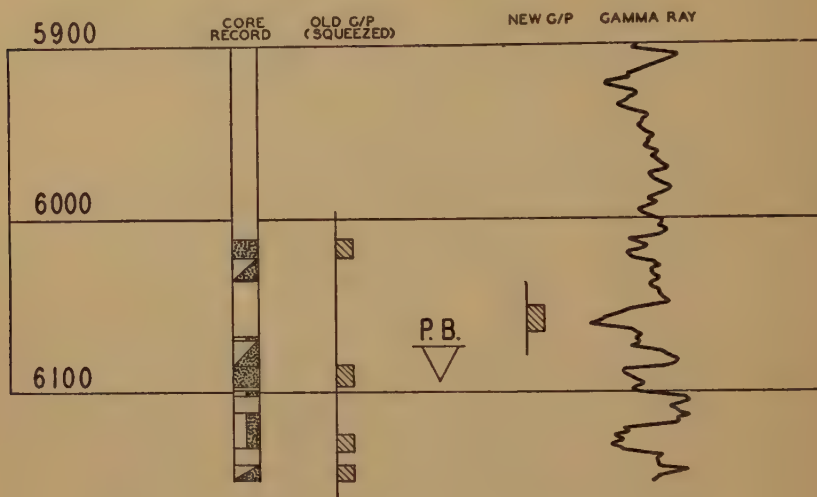


FIG. 2.—GAMMA-RAY LOG APPLIED IN PLUG-BACK TO UPPER PAY.

with 100 sacks of cement under a pressure of 2500 lb. per sq. in., and set a packer at 6000 ft.—11 ft. above the uppermost perforations. Fifty-eight sacks of cement was forced into the formations, 28 sacks was left inside the 7-in. casing, and 14 sacks was washed out through the 2½-in. tubing. The top of the cement plug was at 6073 ft., and with this as a new bottom, the 7-in. casing was gun-perforated with 27 holes from 6050 to 6065 ft. After a test to determine the potential, the well was completed as a gas well, with sufficient volume to satisfy the local needs.

SALT-WATER DISPOSAL

Fig. 3 illustrates a driller's log and a gamma-ray log of a well drilled and completed by cable tools in February 1920 in the Electra field, Wilbarger County, Texas. The initial daily production was 30 bbl. from a depth of 1905 to 1930 ft., which is the main pay sand of the field.

Because of salt-water encroachment, the

well was run for the purpose of verifying the stratigraphy of the driller's log, and to determine the exact depth and thicknesses of any cased-off sandstone or limestone formations that could be used for the disposal of salt water.

After the log had been run, the well was plugged back, in February 1944, to 1802 ft., where the 7-in. casing was set originally. The well then was gun-perforated with 75 holes in the zone designated A, between 1340 to 1365 ft., and with 39 holes in the zone designated B, between 1483 to 1498 ft. In May 1945 a total of 150 bbl. of salt water per day was being pumped into these two beds at a pressure of 400 lb. per sq. inch.

While the purpose of the gamma-ray log was to verify the stratigraphy, a comparison of the two logs revealed that zones A and B were not indicated on the original driller's log. The absence also of the other sandstone or limestone formations as disclosed by the gamma-ray log apparent is

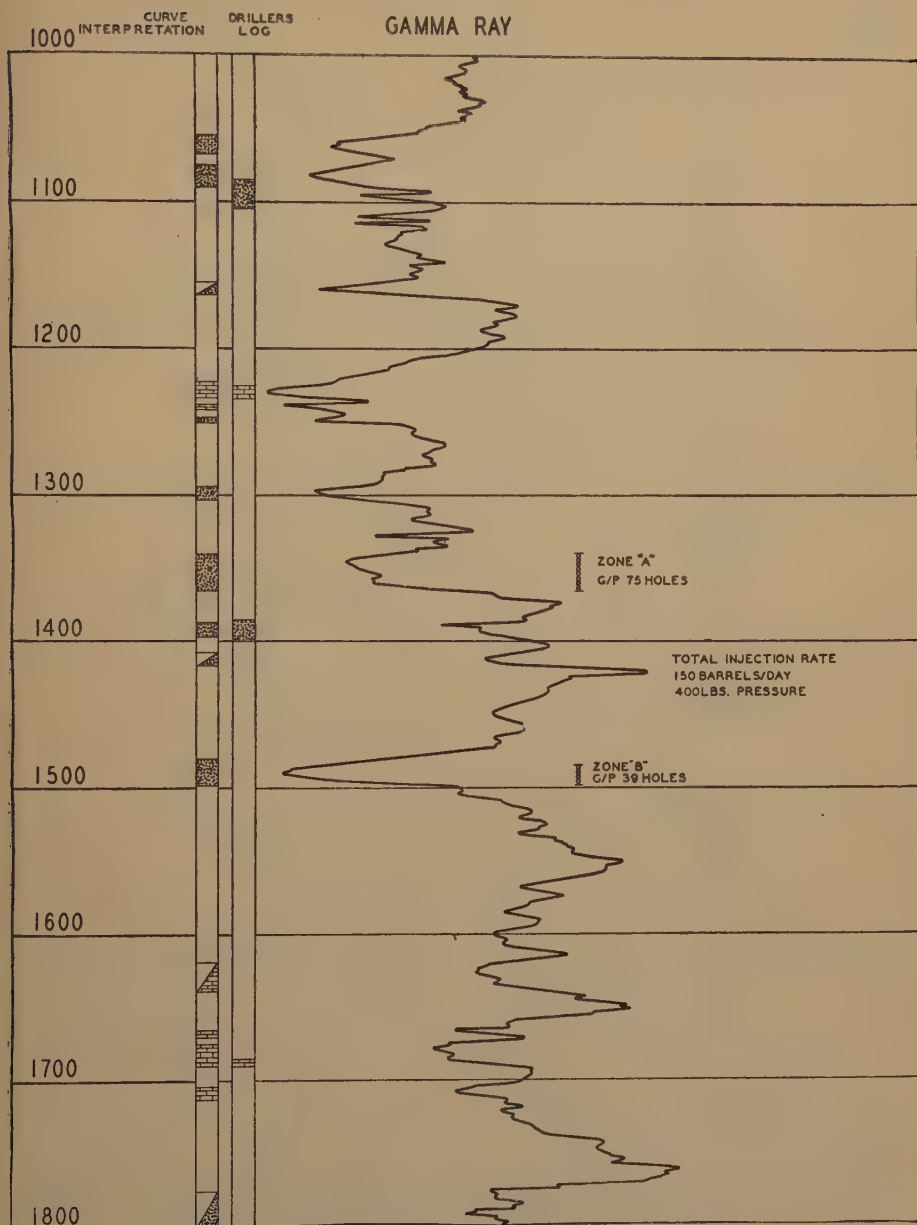


FIG. 3.—GAMMA-RAY LOG APPLIED IN LOCATION OF SALT-WATER DISPOSAL SANDS.

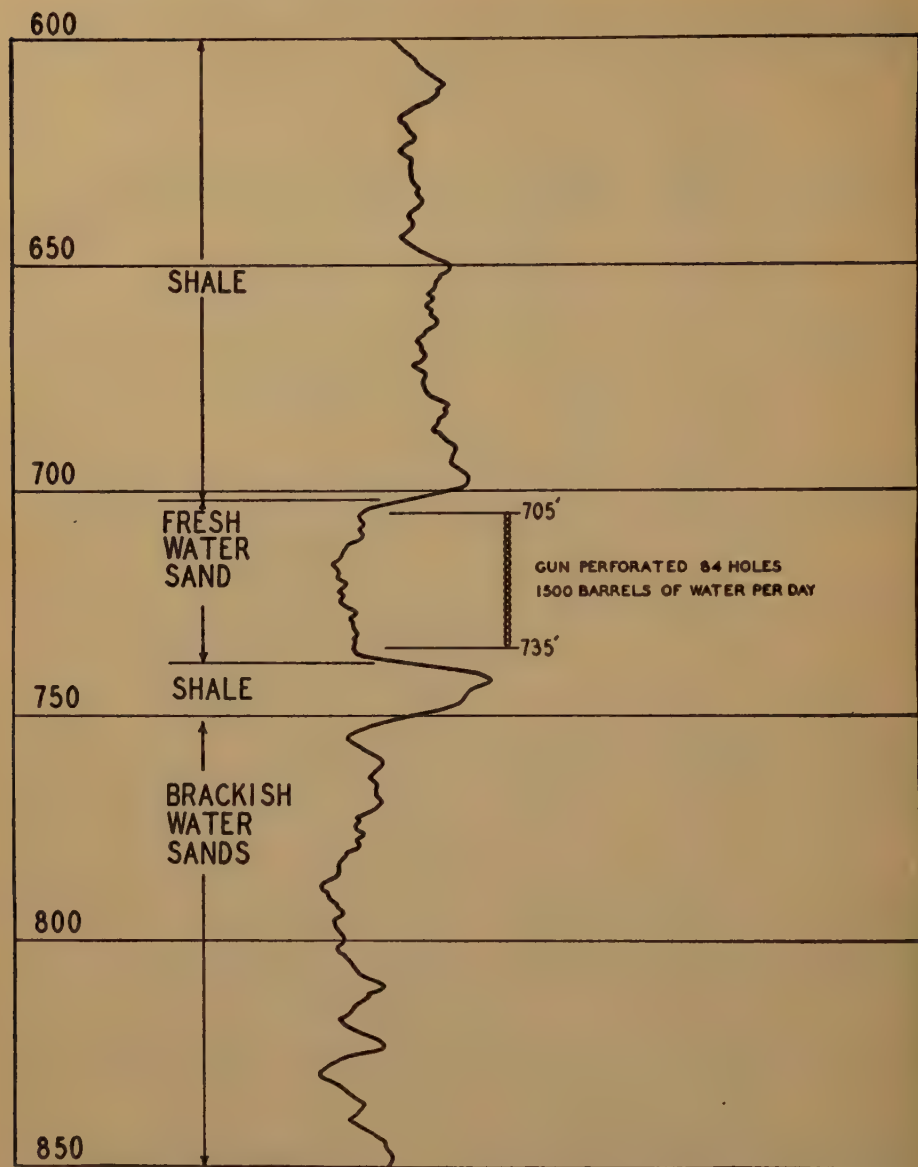


FIG. 4.—TYPICAL APPLICATION OF GAMMA-RAY LOG IN LOCATION OF POTENTIAL FRESH-WATER SANDS, DRISCOLL FIELD, TEXAS.

from the upper section of the log. The disagreement regarding the tops and thicknesses of the zones will be noted in the

10 $\frac{3}{4}$ -in. surface pipe, which was known to be at some depth below 700 ft. The fresh-water-bearing sandstone was found be-

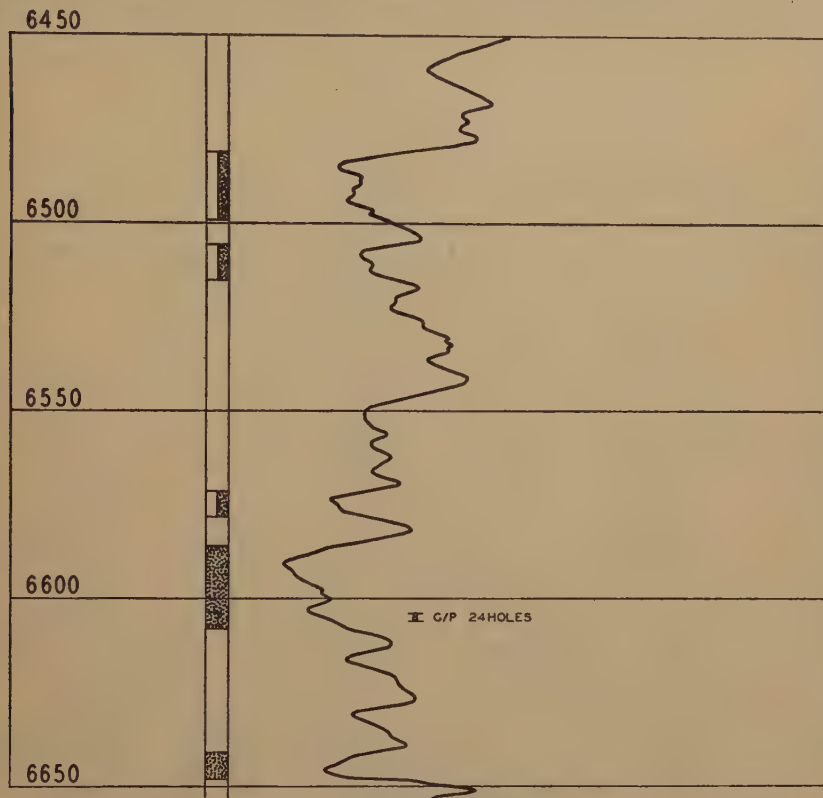


FIG. 5.—GAMMA-RAY LOG APPLIED TO LOW-GAS-OIL-RATIO RECOMPLETION.

sections of the two logs that are in partial agreement as to the lithology of the zones.

FRESH-WATER SUPPLY

Many depleted wells, or dry holes, could be utilized for fresh-water supply instead of abandoning and terminating their period of usefulness.

Fig. 4 illustrates how a dry hole in the Clara Driscoll field, Nueces County, Texas, was used to supply fresh water for a ranch on which the former supply had failed, and incidentally, to supply water for a number of near-by drilling operations.

The gamma-ray log was run to locate a sandstone stratum behind the cemented

tween 702 and 739 ft., and the casing was gun-perforated from 705 to 735 ft., with 84 holes of 1 $\frac{5}{32}$ -in. diameter.

Water rose to within 10 ft. of the surface, and the well was equipped with a windmill and electric pumps on separate strings of tubing. Production of as much as 1500 bbl. of fresh water per day has been reported, with no appreciable reduction in hydrostatic head.

As a result of this work, another rancher, who was in desperate need of water, ordered a gamma-ray log of an abandoned well that was down dip from the well shown in Fig. 4. The same sandstone stratum occurred at a depth of 750 ft., and after the

top 25 ft. of the bed had been perforated the well produced at a comparable rate.

LOWERED GAS-OIL RATIO

The Webb sand in the Flour Bluff field was cored continuously and the cores indi-

The operators in this field were faced with the problem of precise recompletion after plug back, and in order to eliminate any doubt, gamma-ray logs were obtained to locate, accurately, the relative positions of the sand and the bottoms of wells after

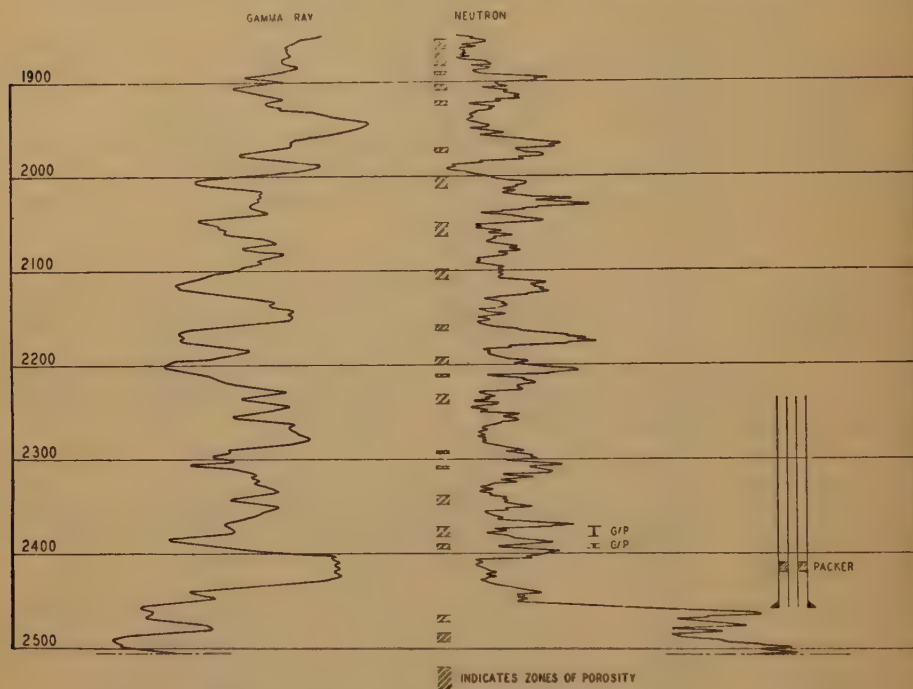


FIG. 6.—COMBINATION RADIOACTIVITY LOG INDICATING ZONES OF POROSITY.

cated a gas-bearing stratum. Production data showed that the reservoir had an expanding gas cap. The depletion to non-commercial quantities of oil from the Phillips sand had caused some operators to plug back their wells to the Webb sand, and to test the extreme bottom of the sand. By selectively gun-perforating a precise interval, commercial quantities of crude oil were produced from an indicated gas-bearing stratum. The change of an expanding gas cap to contracting gas cap was caused by water encroachment, which in its movement has cleansed the sand by pushing the oil upward. Only the edge wells on the steeply dipping flanks, however, produce oil.

plugging back. Following the survey, the casing was gun-perforated for squeeze-cementing from 6598 to 6600 ft., to separate the gas and oil, and later the bottom 2 ft. was perforated with 24 holes from 6604 to 6606 ft. The results were most encouraging. The well produced at the rate of 108 bbl. of pipe-line oil on $\frac{1}{8}$ -in. choke, with a gas-oil ratio of 1450 cu. ft. per barrel. The gamma-ray log is playing a vital role in this field, where low ratios are of prime importance.

LOCATING ZONES OF POROSITY

As mentioned earlier, zones of porosity can be identified by combining the gamma-ray and neutron logs. It will be recalled

that a dense limestone normally will be recorded as a minimum relative value on the gamma-ray log whereas on the neutron log it will be reflected as a maxi-

For Oil Production

Fig. 6 illustrates the manner in which the foregoing response patterns were used to complete a well in the Wimberly pool,

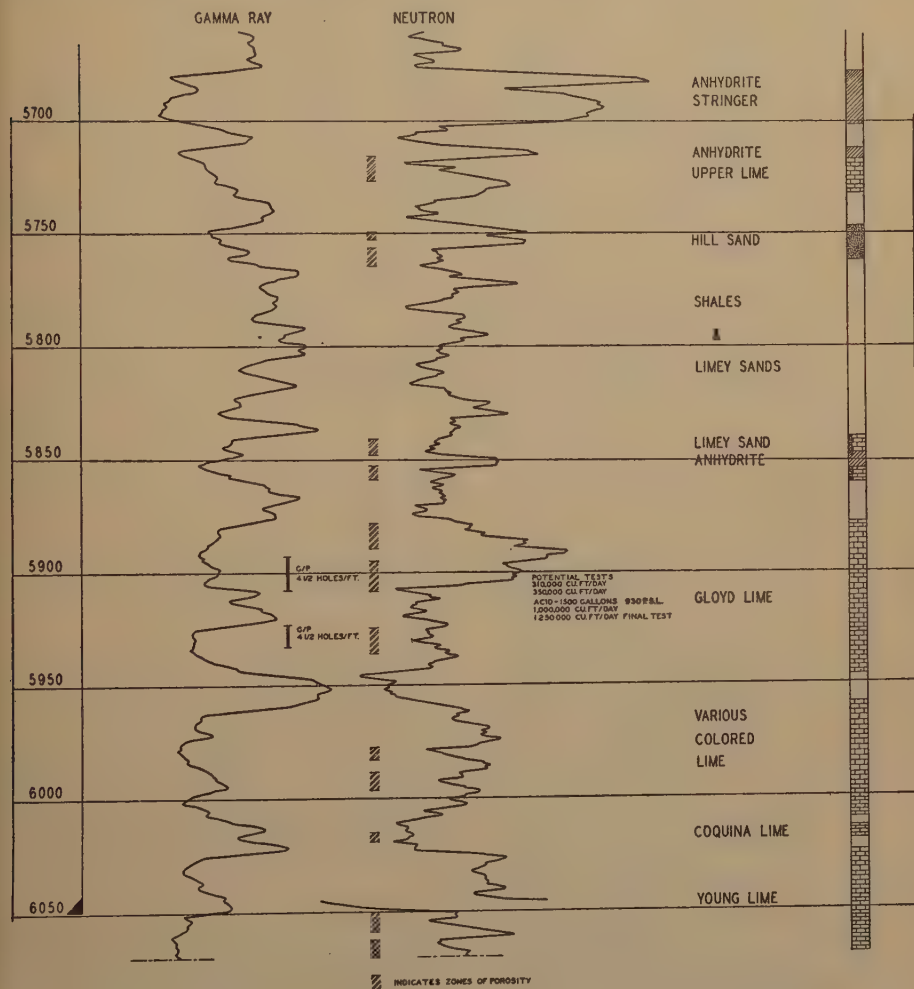


FIG. 7.—TYPICAL COMBINATION RADIOACTIVITY LOG IN THE RODESSA FIELD.

imum relative value, because of the absence of formation fluids. Any zone of porosity in a limestone normally will be indicated by a shift to the left of the neutron curve, because of the effect of the hydrogen associated with formation fluids occupying the pore spaces.

Jones County, Texas, in which the hole was drilled through the Hope limestone, and the casing was set on top of the Gunsight limestone. No electrical log was run, and no cores were taken.

Gamma-ray and neutron logs were obtained after the casing was set, and the

hole was deepened to the bottom pay at a total depth of 2509 ft. The sharp break on the neutron curve shows the casing seat to be 2458 ft., which compares with 2460 ft.

FOR GAS PRODUCTION

Another illustration of the application of the two curves in the location of porous zones within limestone sections, and the



FIG. 8.—RADIOACTIVITY PERMEABILITY STUDY.

shown on the casing record. The varied character of the formations is shown clearly by the radioactivity log. Zones of porosity within the limestones are indicated by the crosshatched blocks in the column between the two curves.

From these indications the zones from 2372 to 2387 ft., and from 2390 to 2395 ft. in the Hope limestone were gun-perforated. The porous streaks in this stratum, together with the lower open-hole section, were treated with 1000 gal. of acid. A dual completion was made by setting a packer and side-door choke assembly between the two limestone zones. On potential test, the upper zone flowed at the rate of 80 bbl. per hour through 2-in. diameter flow line, and the lower zone flowed at the rate of 65 bbl. per hour through a 2-in. diameter flow line. The allowables for both strata are 60 bbl. per day.

production of gas known to exist in the sections, is given in FIG. 7. This combination log of a well in the Rodessa field, Louisiana, indicates the porous streaks in the Gloyd lime. The combination radioactivity survey indicates the utility of the tool in fault-line producing fields, where the porosity in the main pay zones is spotted.

The Rodessa field has little information that is correlative from well to well, and the economy in workover operations is paramount. Rather than gun-perforate from correlative core records, the owner of this well preferred to run the survey for a record, and gun-perforate selectively. As the former pay zone was in open hole, it was desirable to log its porosity, and also accurately locate the casing seat, which can be accomplished easily with the neutron log. The 7-in. casing was found at a

depth of 6049 ft., where a sharp shift to the left was observed on the neutron curve. Clear definition of all the formations is depicted by the gamma-ray curve and of the porous zones by the neutron curve, which are indicated on the chart by the crosshatched blocks. To eliminate bottom-hole water adequately, a wire-line bridging plug was set at a depth of 5975 ft., and three sacks of cement was dumped on top.

The Gloyd limestone was selectively gun-perforated according to the neutron indications from 5893 to 5908 ft., and from 5923 to 5932 ft. The production test showed an immediate flow of 310,000 cu. ft. of gas per day, which gradually increased to 350,000 cu. ft. per day.

After acidizing through the gun perforations with 1500 gal. of acid at a maximum pressure of 930 lb. per sq. in., the well increased in flow to 1,000,000 cu. ft. per day, and finally was completed with a test of 1,250,000 cu. ft. per day. When that production declines to a point where further workover is necessary, the additional zones of porosity indicated on the log may be tested, to extend further the life of the well before abandonment.

PERMEABILITY STUDIES

Work of an experimental nature is being done with regard to the application of radioactivity logging to obtain what properly may be termed a "relative permeability profile" in limestone producing horizons.

The specific need for such information was suggested by engineering studies in various limestone producing fields for the selective completion of wells to inject gas or water into the producing horizons for secondary-recovery operation.

The procedure consists, essentially, of running a gamma-ray log to provide a lithologic log of the well, and the neutron curve to locate possible fluid-bearing zones. This is followed by pumping a radioactive tracer, mixed with salt water or oil under

pressure, into the producing horizon. By successive runs of the gamma-ray curve the distribution of the radioactive fluid into the permeable zones is indicated on the log.

Because the work to date has not been released for publication, a hypothetical illustration is shown in Fig. 8. It will be noted on the log that the intrusion of the radioactive fluids into the most permeable zone is indicated by successive gamma-ray surveys, which complement the neutron log for proper interpretation of porosity and relative permeability.

A convenient radioactive tracer may be obtained by a laboratory process from a bromide of the element radium. This substance may be converted to a salt or soap solution, which is completely miscible with the liquid in a well.

Conceivably, in any one area where radioactive tracers are used, the natural radioactive strength of the subsurface formations may be altered and thus destroy the basic data upon which radioactivity surveys are made. Consideration should be given to the use of radioactive tracers having a relatively short life period, so that the effect of the tracer will disappear in a definite time. Many suitable substances possessing desirable properties are unavailable at present.

It is reasonably assumed that the main purpose of a tracer is not only to study the permeability of one well, which in itself would be significant, but rather to study a series of wells on strike, to determine whether permeability is continuous vertically and horizontally.

The practical application of radioactivity logging in such situations will be determined best from the results of further experimental investigation over a wider range of conditions. It is hoped that it will be a means of supplying pertinent subsurface well data in fields where insufficient information relative to the producing horizons is available not only for intelligent

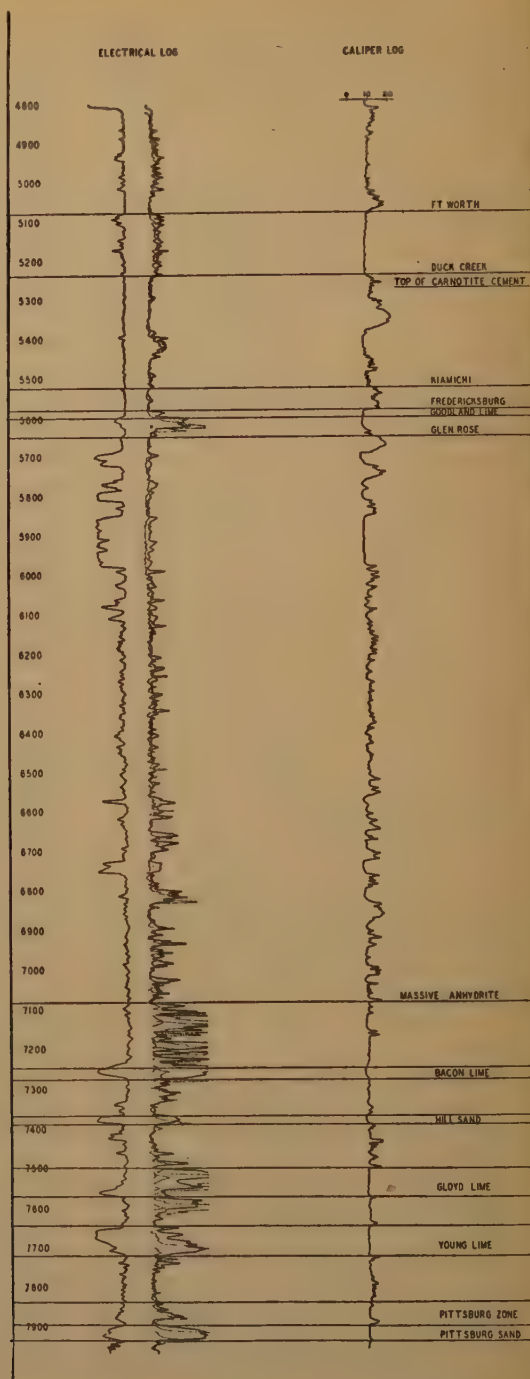
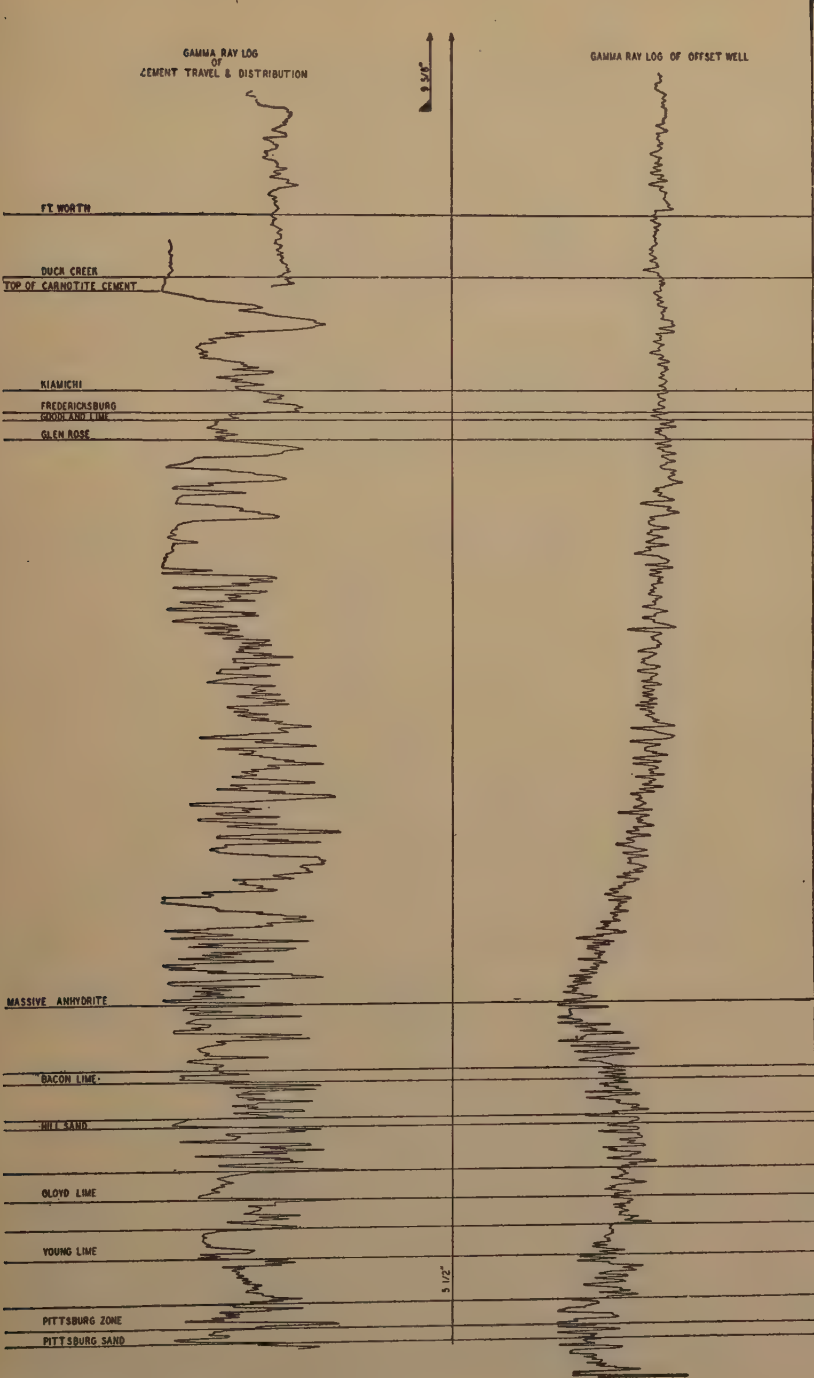


FIG. 9.—GAMMA-RAY ILLUSTRATION



OF ORIGINAL OIL-STRING CEMENTING.

planning of secondary-recovery projects but also for primary-production operations.

DETERMINATION OF CEMENT PLACEMENT

Original Casing

Frequently, during the development of a field, or in the completion of a particular well, it is important to determine accurately the actual cement fill-up behind the oil string to compare with the conventional methods now employed.

The vertical travel of the cement, as well as an indication of mass distribution, can be obtained by the use of powdered carnotite mixed with the cement. Carnotite is highly radioactive because of its uranium and potassium constituents, and consequently is an ideal tracer. By proportioning the mixture so that the intensity of the gamma-ray response is considerably greater than that usually obtained from the formation alone, it is easy to distinguish the presence of the cement by comparison with natural formation radioactive intensity.

A mixture containing $\frac{1}{4}$ to $\frac{1}{2}$ lb. of carnotite per sack of cement appears to be a satisfactory proportion over a wide range of conditions. The packaged carnotite is introduced at the mixing hopper, and because of its nearly colloidal texture and specific gravity, it remains in fairly stable mixture with the cement slurry without settling out.

Fig. 9 illustrates a typical investigation of this nature conducted in the New Hope field, Franklin County, Texas. The various steps in the study are shown in sequence from left to right. An electrical log to obtain data on the formations and contained fluids was run. An open-hole caliper survey then was made to determine the variations in the hole diameter. This survey indicated an average diameter of hole of 11 in., which was drilled with an 8 $\frac{3}{4}$ -in. bit; the enlargement was caused by considerable sloughing of shales and unconsolidated sands.

From the data obtained from the caliper survey it was determined that 1200 sacks of cement would be required to protect all possible productive horizons for testing. The 5 $\frac{1}{2}$ -in., 17-lb. casing was landed at a depth of 7929 ft., and was cemented with 1160 sacks of cement, mixed with $\frac{1}{4}$ lb. of carnotite per sack. Thirteen sacks was left in the casing, 1147 sacks being displaced behind the pipe.

After normal setting time had elapsed, the cement was drilled out to the bottom of the casing and a gamma-ray survey was made. The sharp reduction in intensity at 5262 ft. indicates the upper limit of the carnotite-laden cement.

Although it is possible to record the natural formation radioactivity as the pipe is suspended prior to cement, the risk of sticking the casing is too great. In many fields, the danger of losing instruments by cave-ins is too great to make a base log in open hole, but an alternative is to log an offset well. Such a method was used in this instance, and is shown on the extreme right of Fig. 9.

The illustration shows that the cement protects all the important zones except those immediately below the surface pipe, which can be squeezed later if deemed necessary. In addition, the gamma-ray log correlates extremely well with the caliper and electric logs in revealing that the bulk of the cement was opposite shales, which normally wash out to a greater degree than the sands.

Squeeze Cementing

Because the conditions attending the cementing of the oil string permit a fairly close estimate of the travel of the cement, the same is not true of squeeze cementing. For many wells it is of considerable importance to have an accurate knowledge concerning the final location of cement squeezed behind the pipe after the original cementing. Because of the various constrictions and the pressures required, it is

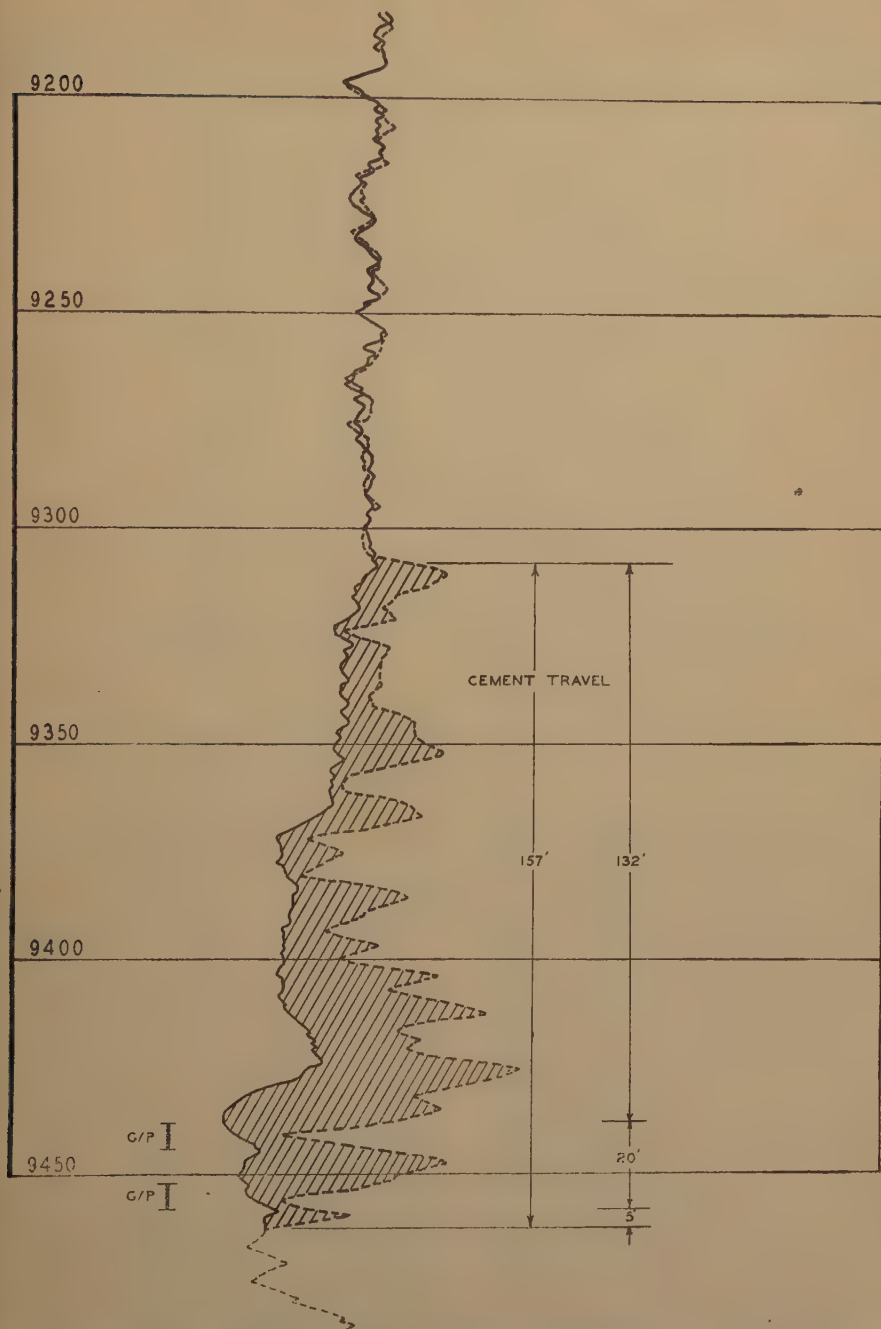


FIG. 10.—TYPICAL SQUEEZE CEMENTING, WITH CARNOTITE SQUEEZE, SOUTHERN LOUISIANA.
 "Solid line, first run; broken line, second run."

impossible to predict how much cement can be squeezed, and whether the bulk of the cement will go up or down, or what effect the lateral distribution as a result

A second gamma-ray survey was run to a point some 26 ft. below the depth of the first one as indicated by the dashed line. By superimposing the second curve on the

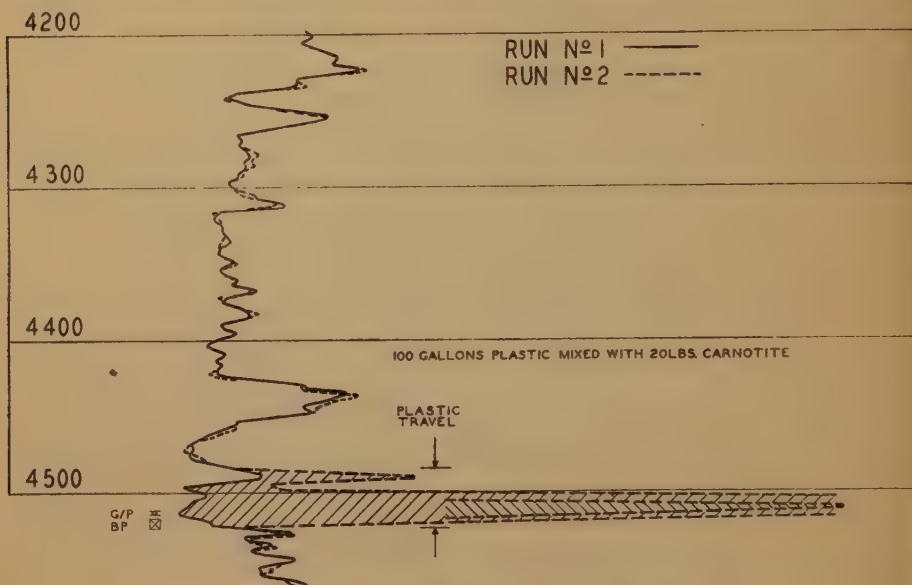


FIG. 11.—TYPICAL PLASTIC SQUEEZE, EAST TEXAS.

of compaction and wedging will have on the vertical limits.

Fig. 10 illustrates typical carnotite squeeze cementing on a well in southern Louisiana. The well was prepared for the squeeze by setting a drillable bridging plug on a wire line at a depth of 9462 ft. and gun-perforating from 9438 to 9444 ft., and 9452 to 9458 ft., with six holes in each zone. The base survey shown by the solid-line curve representing the gamma-ray intensities of the natural formation then was run.

The well was squeezed through the two sets of perforations with 165 sacks of cement, mixed with $\frac{1}{4}$ lb. of carnotite per sack of cement at pressures ranging from 2000 to 5000 lb. per sq. in. After a 48-hr. set the remaining cement and the drillable plug were drilled out, and circulation was begun to free the inside of the casing of any remaining treated cement.

first gamma-ray curve, the difference in gamma-ray intensities caused by the presence of the radioactive cement behind the pipe is apparent. When emphasized by crosshatching, this difference is clearly discernible.

In this instance the cemented section extends over 157 ft., with the top 132 ft. above the upper perforation, and some 5 ft. below the lower perforation. In other studies of this type it has been noted that the downward travel of the squeezed cement may be as much as one third of the total vertical displacement.

Some conception of the volumetric distribution can be obtained from Fig. 10 by the disclosure that the greater the mass of the treated cement at any point, the greater will be the gamma-ray intensity.

Plastic Squeeze

The properties of commercially available plastics, particularly those that pene-

trate interstitial spaces, enable their use to good advantage in replacing cement under certain critical conditions. Various applications of plastics are understood

finely ground carnotite, through the old perforations at 4514 and 4516 ft. with a pressure of 1300 lb. that built up to a maximum of 1700 pounds.

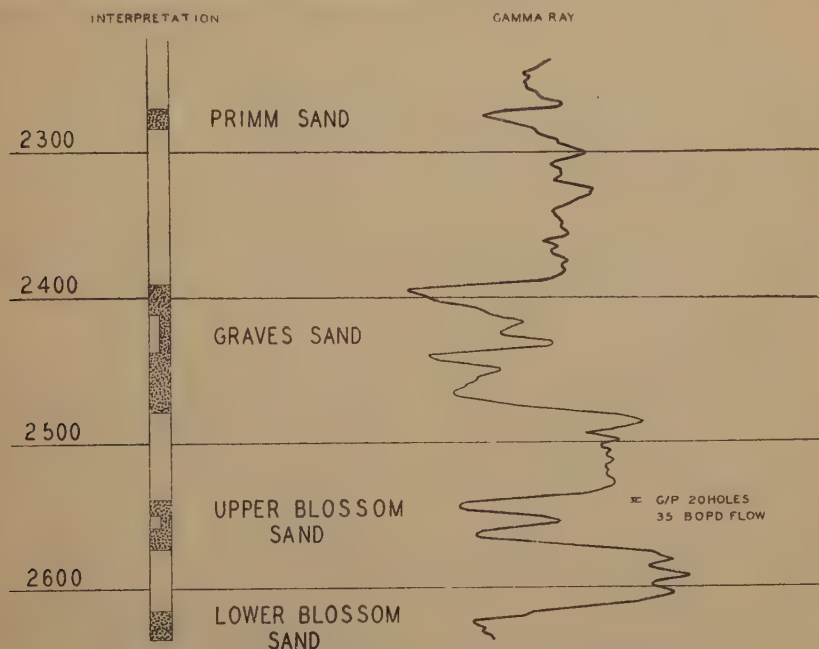


FIG. 12.—GAMMA-RAY EXPLORATION FOR CASED-OFF SANDS.

generally, but it is not so generally known that carnotite can be retained in suspension by plastics while in the fluid state, thus making it possible to conduct investigations similar to those described for carnotite mixed with cement.

Fig. 11 illustrates the displacement obtained on a plastic squeeze applied experimentally on a well in the East Texas area, in an effort to correct an unsatisfactory gas-oil ratio.

Following the standard procedure, a gamma-ray survey first was run to establish the gamma-ray intensities of the natural formation. This curve is shown by a solid line on the figure. The sand of interest is identified by minimum gamma-ray intensity values between 4495 and 5025 ft.

A wire-line drillable bridging plug was set at 4518 ft., and the well was squeezed with 100 gal. of plastic mixed with 20 lb. of

After a sufficient interval of time had elapsed to permit the hardening of the plastic, the plug was drilled, and the hole was conditioned for the second gamma-ray survey, the curve for which is shown on Fig. 11 as a dashed line superimposed on the first curve. Again the crosshatched area represents the limits of vertical travel and the relative mass distribution of the tracer-laden squeeze material.

The extreme intensity obtained on the second survey is not the result of massive accumulation of the plastic behind the casing, or extreme penetration into the sand, but of the high concentration of carnotite used. Expressed in terms of pounds per cubic feet of cement, the concentration is roughly equivalent to 1.5 to 1, or approximately six times as much carnotite as was employed in cement studies in

which $\frac{1}{4}$ lb. of carnotite per sack of cement was used.

GAMMA-RAY ILLUSTRATION FOR EXPLORATION

Scores of wells, usually old wells thought to be depleted of all possible oil and gas production, are abandoned annually. Most of these wells were drilled years ago, prior to present-day scientific technology, and no records, other than incomplete driller's logs, are available.

Many of the wells are abandoned because they have a single pay horizon, but in multiple sands or pay zones it is economically important from the viewpoints of ultimate production, or geophysical correlation, to survey the boreholes. Through geophysical correlation and exploitation, oil wells have been surveyed before abandonment, to obtain information that may be helpful when possible field extensions are considered. Fig. 12 is an example of a survey of a well prior to abandonment in order to test any possible cased-off pay zones.

It is a typical example in the Smackover field, Arkansas, but it is applicable to wells in any area. Many of the producing zones at Smackover are blanket sands, but the Upper Blossom sand is lenticular, and it "shales out" from one location to another. During the development of this field most tests were terminated in the Lower Blossom sand, and shallower zones were disregarded. Subsequent stripper tests and exploratory workovers prompted the survey of depleted wells before abandonment, and excellent production has been reported.

Fig. 12 typifies a gamma-ray exploration for cased-off sands. To eliminate doubt and provide a record, this survey was run to determine the presence of upper beds. A sand was recorded at the Upper Blossom level from 2538 to 2572 ft., with an intermediate sandy-shale break from 2548 to 2558 ft. After plugging back with cement, the casing was gun-perforated with 20 holes

in the top of the upper stringer from 2538 to 2541 ft. The well came in flowing 35 bbl. of oil per day, and enough gas to operate three additional wells on the same lease, which reduced the lifting cost of all four wells. Forty-four months later the well was producing 8 bbl. of oil per day, and was providing enough gas to operate the three additional wells.

When this sand is no longer considered a commercial producer of oil, the operator plans to drill out the plug to the Lower Blossom sand, and to attempt to recover more oil from this section by using the gas from the Upper Blossom sand.

STRUCTURAL CORRELATION ON SHALE

The natural practice of correlating electrical logs on sandstones or limestones is quite similar to the correlation of several gamma-ray curves, because the gamma-ray curve often is quite similar to the natural potential curve of the electrical log. With gamma-ray logs, however, the correlation on shales is dissimilar. This phenomenal difference is accounted for by the fact that shales vary considerably in their radioactive intensities. The chemical constituents of shales, and their type deposits, make characteristic values apparent on the resultant curve. The correlation on shales in Fig. 13 becomes more significant when it is realized that sands could be correlated as with electrical logs, but precision in the location of the fault plane would not be possible. It is also possible that only one fault plane would be assumed rather than the fault block itself. This precise work was made possible through correlation of shales, which, because of different depositional characteristics, vary in gamma-ray intensity. Bentonites, volcanic ash, and marine shales are characterized particularly by high radioactive values, and they have very distinctive characteristics on a gamma-ray log. In Fig. 13, the two marine shales of each well have been clarified by the heavier lines, and through proper cor-

relation they show the traces of the two apparent fault planes of the block. It is reasonable to assume that with the block

field, and they are a great aid in badly faulted fields where the radioactive intensities of shale values are correlatable.

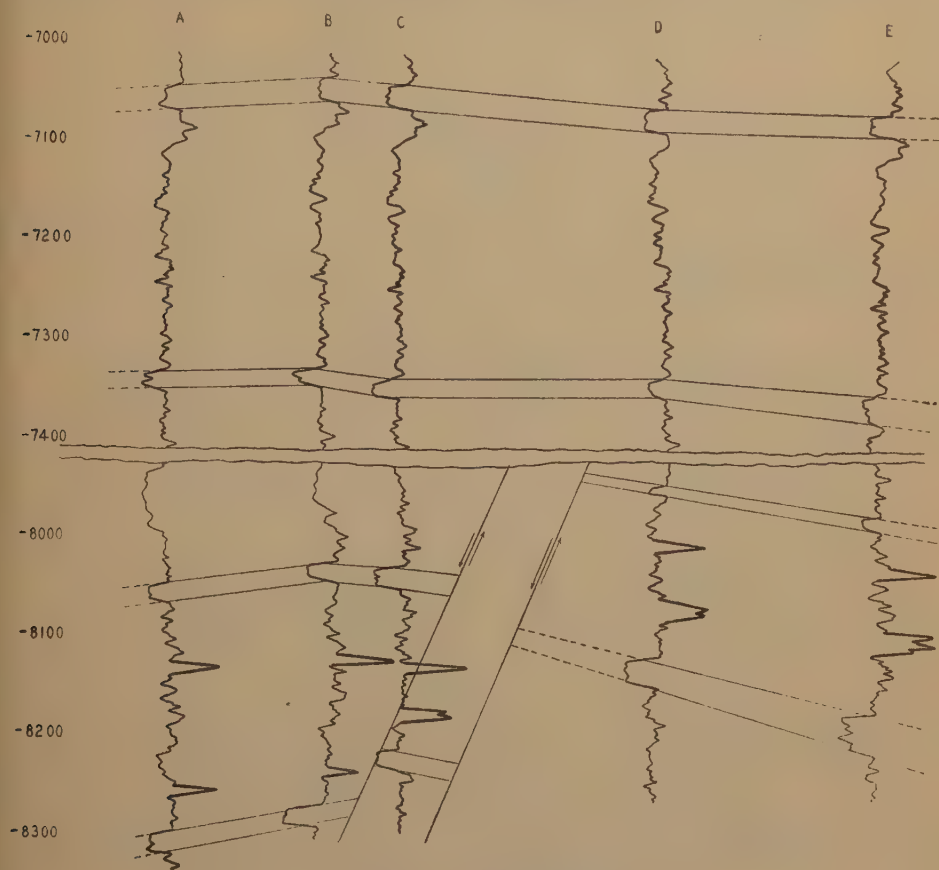


FIG. 13.—STRUCTURAL CORRELATION ON SHALE.

lying between wells C and D, another test drilled between them would find the 8040-ft. sand higher in the fault block, and possibly another productive zone. The normal dip is interrupted by shale correlation as it locates a fault through well C, which, however is not present in offsetting well B. The other fault is known to be present between C and D by correlation of the radioactive shales, and is confirmed by the obvious correlation on sands.

Structural maps can be made with assurance from gamma-ray logs in any

EMERGENCY LOGGING

Under this heading should be grouped the wells in which physical conditions within are such that competent electrical logs cannot be secured normally, but in which a radioactivity log can be obtained to give much of the needed information.

SALT-WATER MUDS

The difficulty of obtaining electrical curves with sufficient character and definition to be significant in salty muds is well recognized. Under such conditions it is

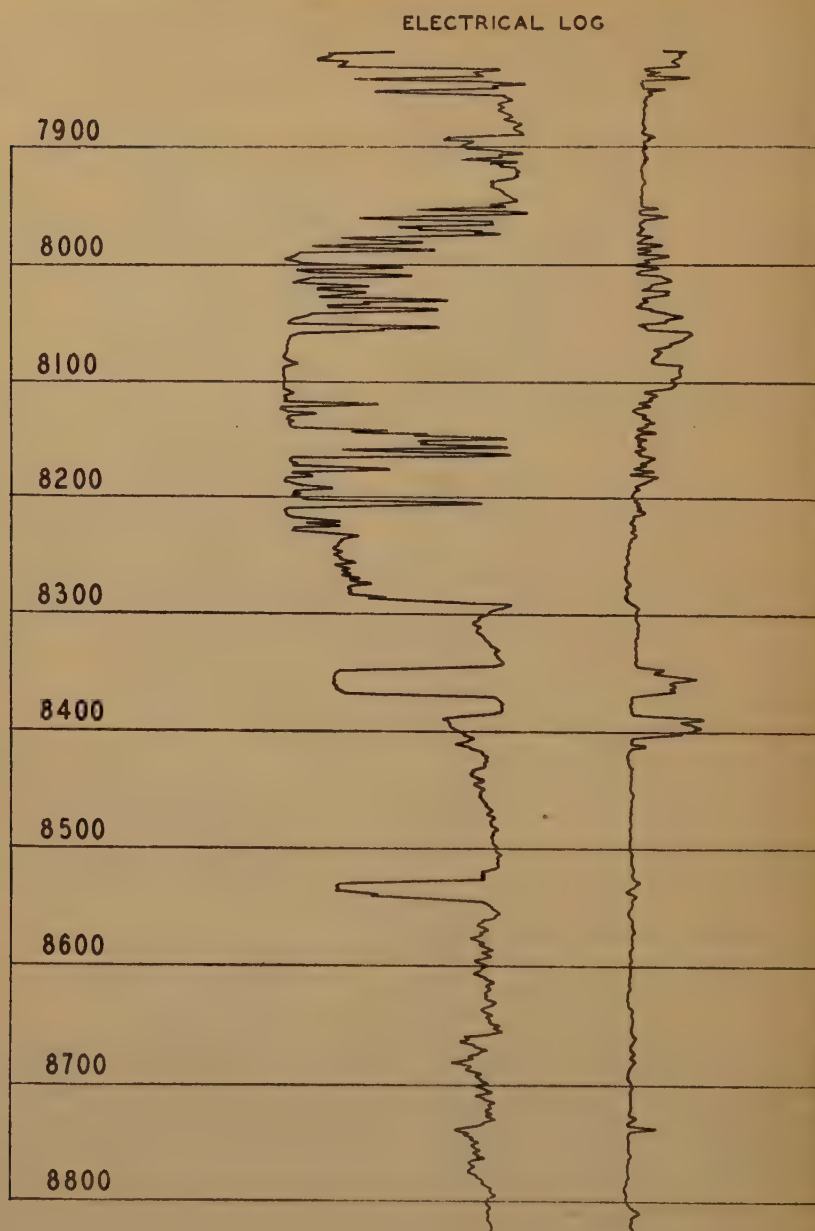
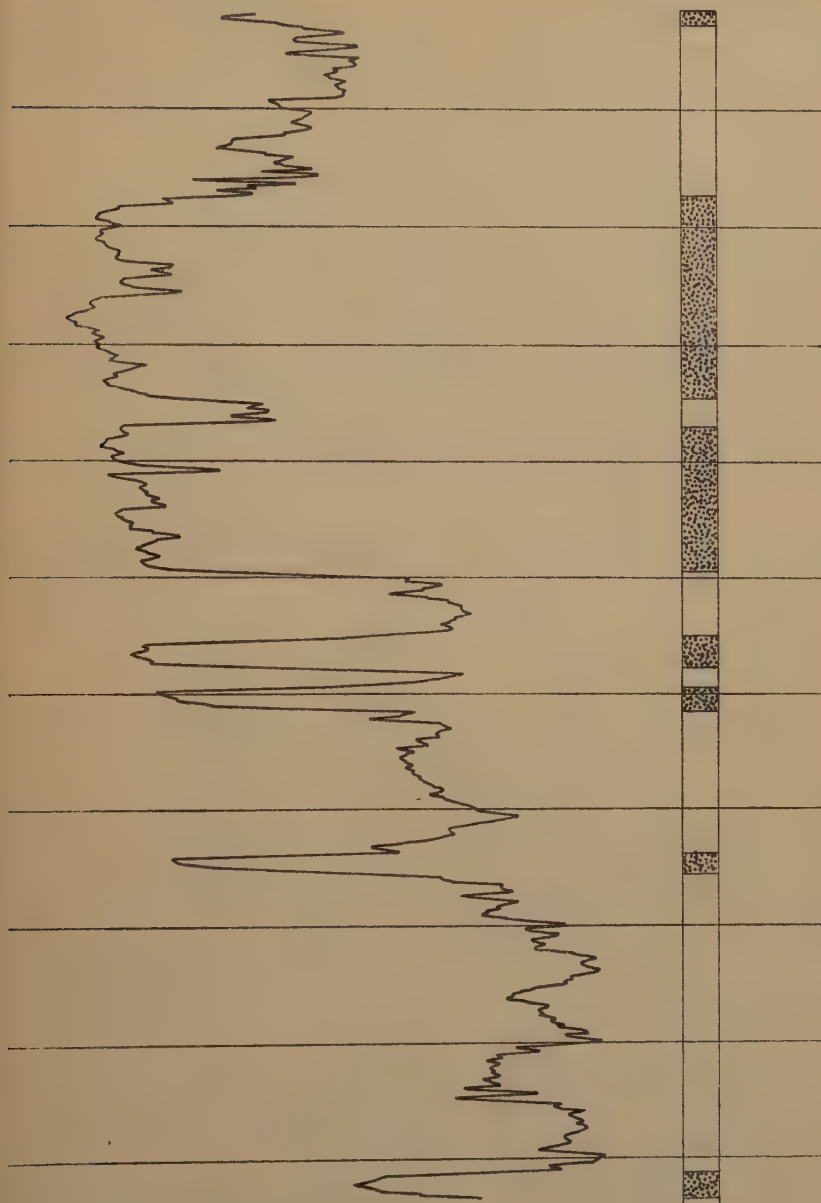


FIG. 14.—OBTAINING STRATIGRAPHIC

GAMMA RAY

INTERPRETATION



INFORMATION IN SALT-CONTAMINATED MUD.

possible to secure either of the radioactivity curves without regard to the composition of the mud.

Fig. 14 illustrates this condition in a

log that covered the doubtful section was run from 8835.5 to 7820 ft. A comparison of the logs over this section shows the definition of the bottom sand on the

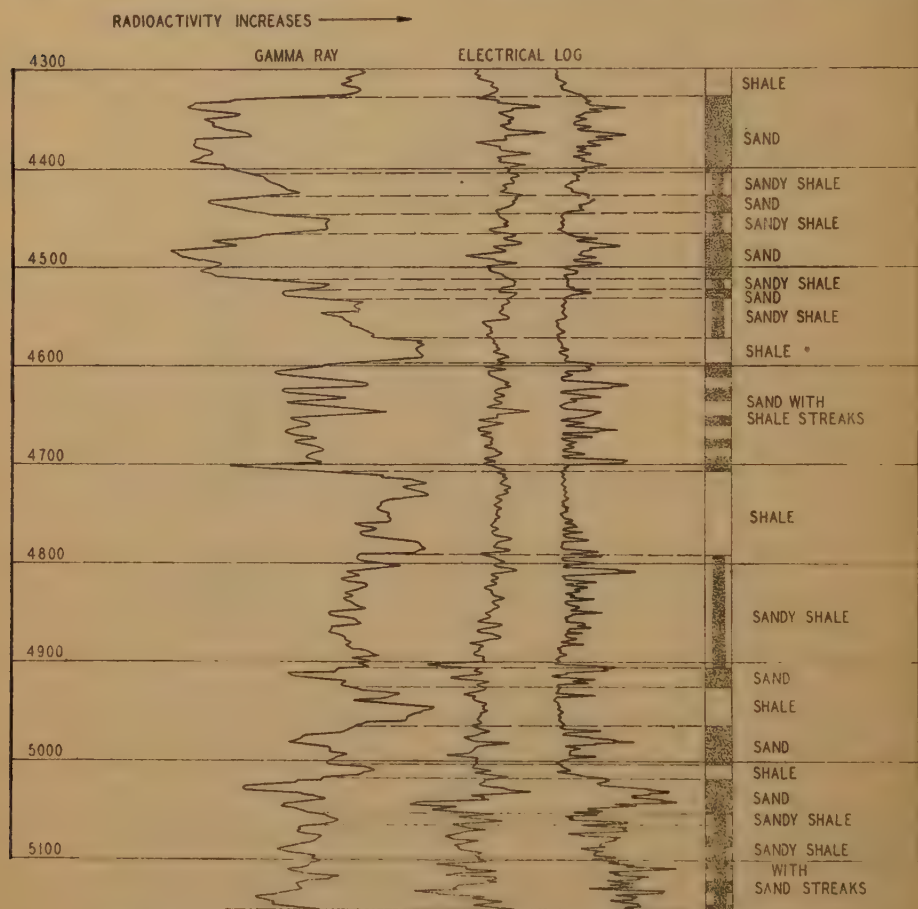


FIG. 15.—COMPARISON OF LOGS OBTAINED IN OIL-BASE MUD, CALIFORNIA.

wildcat well drilled in Assumption Parish, Louisiana. The characteristics of the mud were normal and six electrical logs were obtained successively as drilling progressed and the salt cap was penetrated. The salt lowered the resistivity of the mud to 0.4 at 93°F., and the final electrical log failed to define a known sand a few feet above the salt.

The casing was landed, and after the cement had been drilled out a gamma-ray

gamma-ray log, which is masked out on the electrical log, and the agreement between the two logs on the upper sands, although there is some difference as to their depths.

OIL-BASE DRILLING FLUID

Oil-base drilling fluid is used in several California fields to eliminate the infiltration of water where the productive zones are partially depleted and bottom-hole

pressures are low. Since oil is a dielectric substance, it offers greater electrical resistance, and thus makes it difficult to obtain a satisfactory electrical log.

deep exploratory wildcats, there is always the possibility that the unexpected penetration of an unknown high-pressure gas-bearing sand will upset the planned

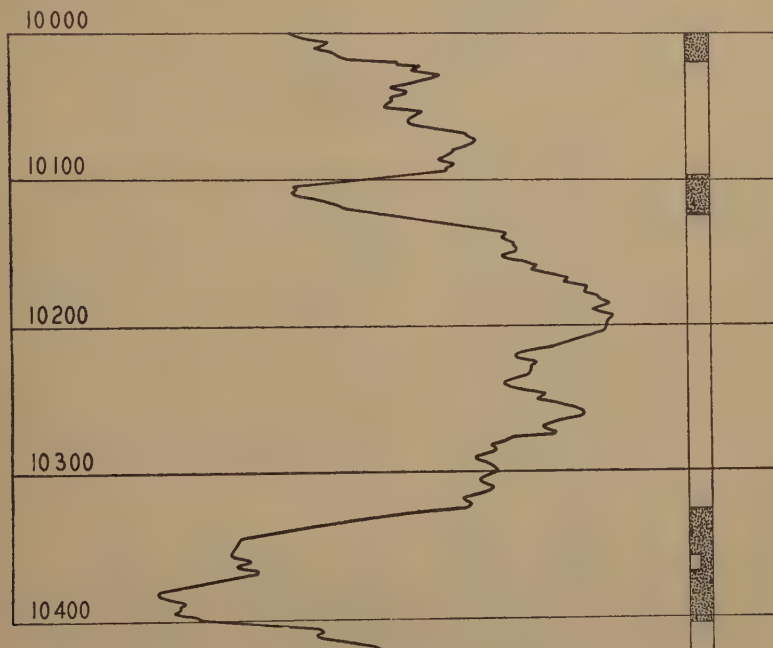


FIG. 16.—GAMMA-RAY LOG AFTER CASING IS SET, TEXAS GULF COAST.

In order to obtain correlation, electric logs have been run by using electrodes that make a sliding contact on the walls of the hole. The nature of this contact with the irregular formation changes in the walls of the hole is unsatisfactory, and tends to produce a curve that is sometimes difficult to interpret.

The gamma-ray log is independent of any contact with the walls of the hole, and reacts normally in oil-base drilling fluids, giving a clear, sharp, definition between sands and shales as shown in Fig. 15. Good correlations are obtained with neighboring electric logs of wells drilled previously with oil-base drilling fluid, and with other gamma-ray logs in the vicinity.

THREATENING BLOWOUT

Despite the extreme care and precautions normally observed in the drilling of

schedules and engineering procedure of electrical logging intervals, and mud controls.

When such a sand is penetrated the use of extremely heavy muds and the speeding up of operations leading to the introduction of casing usually prevents the accumulation of vital information on the bottom section of the hole normally obtained from cores and electrical logs. After casing has been set safely in such a well, a radioactivity log can be run to obtain neglected information, or as a check upon uncertain information relating to the type and depth of formations cased off.

Fig. 16 illustrates the results obtained under these conditions on a wildcat drilled on the Carrizo-Wilcox trend of the lower Gulf Coast. It was necessary to raise the mud weight while drilling below a depth of 10,000 ft., and to maintain it

approximately at 16.8 lb. per gallon. Under these conditions no electrical log was obtained and 5½-in. casing was set through the Wilcox formation. The gamma-ray

greater volume of fluid had to be lifted to obtain the 20 bbl. per well allowable in the East Texas field. The well was producing 18 per cent of the fluid as bottom water at

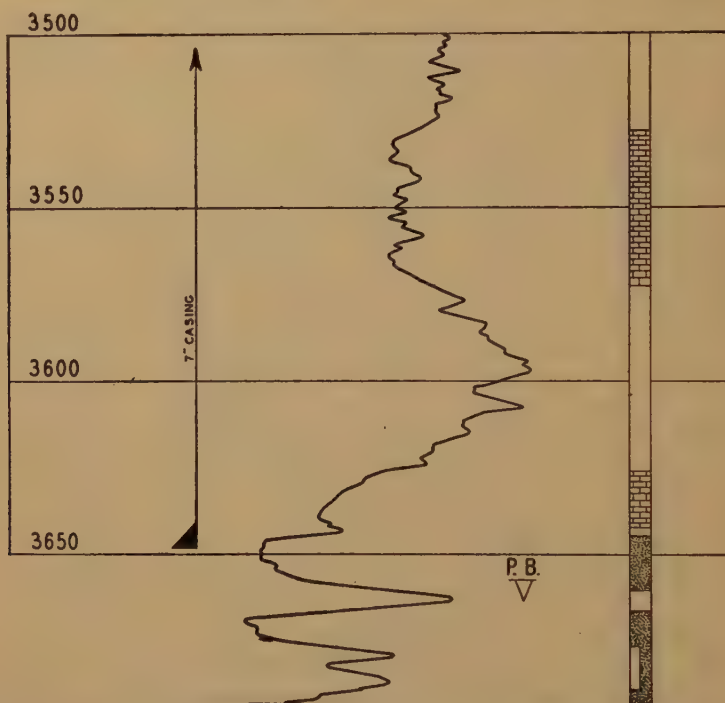


FIG. 17.—GAMMA-RAY LOG INDICATES PRESENCE OF PARTIALLY CASED-OFF SAND.

survey was run after the cement plug was drilled, to supply additional information and to check the known data in the upper part of the hole. The entire log of the well was then complete, and correlation with subsequent tests was made easier.

LOCATING CASING SEAT FROM GAMMA-RAY LOG TO PREPARE FOR SHUTTING OFF BOTTOM WATER.

Fig. 17 shows a gamma-ray log of a well in the East Texas field, made to determine the exact depth of the casing seat before plugging back. The operator had aimed to set the 7-in. casing at the base of the Austin chalk for an open-hole completion. After several years of production, the well gradually went to water, and as a result, a

the time of the survey. The gamma-ray log shows the top of the Woodbine sand at 3645 ft., and by using the collar finder, a casing seat was located 3 ft. below the top of the Woodbine sand instead of at the base of the Austin chalk. After the well was surveyed and the situation studied, the well was plugged back to 3657 ft., and 15 per cent of the water production was eliminated. Production records in January 1945 showed only 3 per cent water. Future gun-perforating will permit a rejuvenation of the well when the open-hole zone has been depleted of its oil.

The records of other wells on this same lease with questionable casing programs were as follows:

Well	Production before Plug-back, Per Cent		Production after Plug-back
	Oil	Water	
A	67	33	Pipe-line oil
B	1	99	1.2 per cent water
C	65	35	Pipe-line oil
D	50	50	5.8 per cent water

GAMMA-RAY LOG USED TO CLARIFY DOUBTFUL MEASUREMENTS

Discrepancies in well-depth measurements continue to appear, and the problem of obtaining correct measurements has been receiving considerable attention by engineers in recent years. Not only has this problem been evident because of the present trend toward the development of relatively thin strata at greater depths, but in remedial work on old wells in the processes of primary and secondary recovery as well.

Much unnecessary squeeze cementing leads to the attempt to complete wells in zones where inaccurate depth measurements have been reported. Fig. 18 illustrates a typical problem in a Gulf Coast field. According to the gun-perforating record charted on the figure, the casing was gun-perforated from 8839 to 8842 ft., which is in the lower part of the sand, as indicated on the electrical log. The well tested pipe-line oil, and was produced for a time until subsequent remedial work was necessary to shut off bottom-hole water. After the original producing zone had been squeezed off, the well was gun-perforated several times between the depths of 8826 to 8842 ft., and on tests following each operation the well produced some oil with excessive quantities of salt water. The last two tests, between 8822 and 8832 and 8826 and 8833 ft., however, showed no production of oil or water.

The gamma-ray log was run to check the accuracy of the electrical log for the purpose of measurements. The producing zone was found somewhat lower than was indi-

cated by the electrical log, accounting for the dry tests that were made in shale strata.

The well was gun-perforated again from 8835 to 8839 ft., and it was completed to produce commercial quantities of oil with some salt water.

CASING-COLLAR LOCATOR

Experimental work is being done to develop an electrical collar locator that records the depths of casing collars simultaneously with the gamma-ray log.

The electrical collar detector is an accessory to the subsurface gamma-ray instrument, and is designed to transmit electrically on to the recorder at the surface an indication of the location of each collar. The record for each is made by an independent pen on the same chart with the gamma-ray log. Fig. 19 is an illustration of the casing-collar log together with a typical gamma-ray log.

This device offers a method of obtaining extreme accuracy in well-depth measurements. The formations defined by the gamma-ray log may be correlated definitely with permanent bench marks that are less than half a joint of casing away from a zone of interest. The same casing collars can be relocated by means of a collar-locating device attached to other tools to establish a zone of interest at any future time. Subsequent testing or cement jobs that normally change the apparent total depth of a well will have no effect on the relocation of the collars.

CONCLUSIONS

The versatility of radioactivity well logging is shown by the numerous examples in this paper. This new tool should be a great aid to the oil industry because it is adaptable to a variety of problems that are met either in new or old wells.

ACKNOWLEDGMENT

The writers gratefully acknowledge the cooperation of numerous geologists and

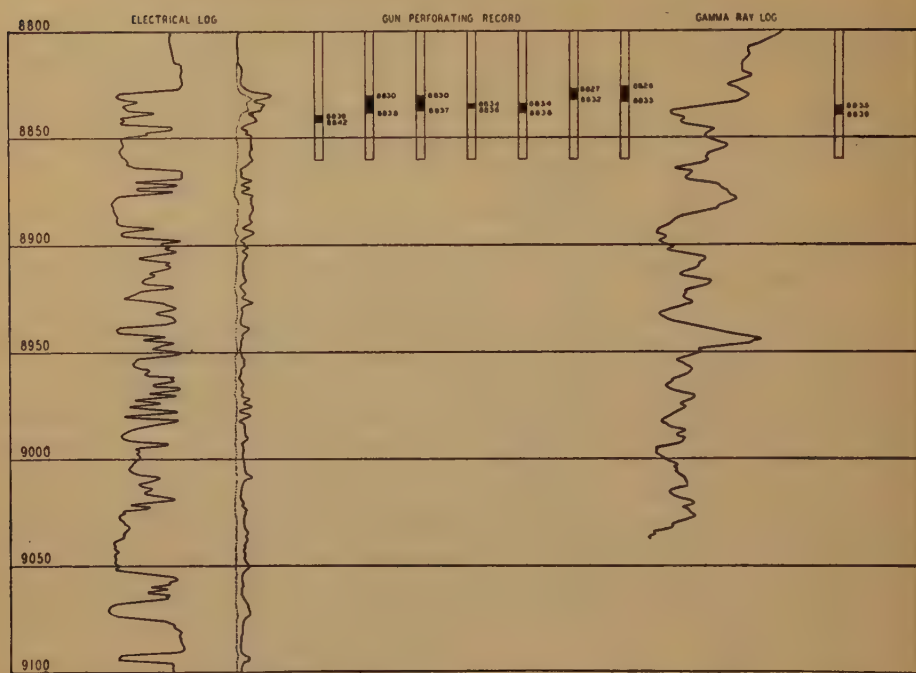


FIG. 18.—GAMMA-RAY LOG CLARIFIES MEASURE DISCREPANCY.

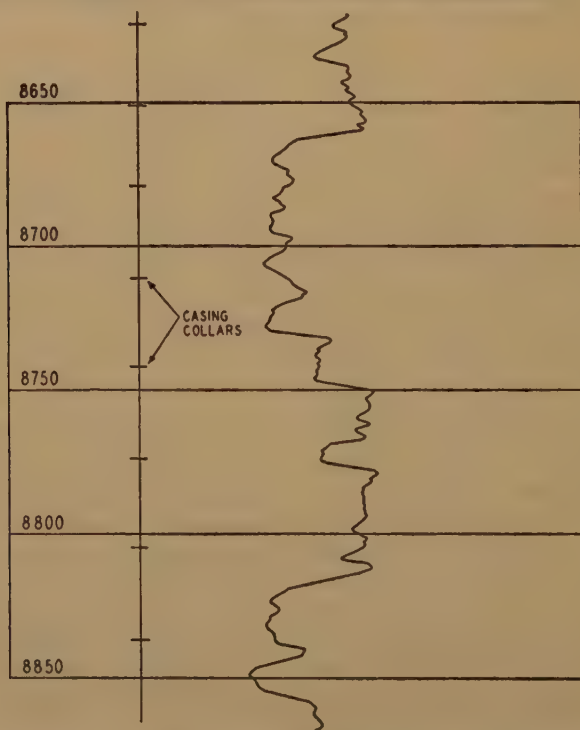


FIG. 19.—LOG OF ELECTRICAL COLLAR LOCATOR RECORDED SIMULTANEOUSLY WITH GAMMA-RAY LOG.

engineers associated with independent and major oil companies who made this study possible by releasing logs and production data. They thank Mr. Charles B. Carpenter, Bureau of Mines, Dallas, Texas, and Mr. Henry C. Cortes, Magnolia Petroleum Co., Dallas, Texas, for reviewing and criticizing the manuscript and the Messrs. J. D. Hughes and A. B. Winter for technical assistance. They appreciate the permission of the Lane-Wells Company for publication of the paper.

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 - A. B. Winter, M. C. Bowsky, and J. C. Stick, Jr.: Correlation between Electrical Logs and Radioactivity Logs.
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 - A. B. Winter: Use of Neutron Curves.

Volume 9

 - J. L. Neale: Proper Completion Assured by Radioactivity Logs.
 - J. C. Barcklow: Adaptability of Radioactivity Logs to Limestone Zones in Old and New Wells.
 - R. L. Alder: Recompletions Based on Radioactivity Logs.
 - J. D. Hughes: Radioactivity Logging Provides Valuable Data for Gulf Coast Operators.

Volume 10

 - J. L. P. Campbell: Checking Your Cement Jobs with Radioactivity Logging.
 - C. T. Maxwell: Radioactivity Economics.
 - C. T. Maxwell: Radioactivity Logs Prove Advantageous in Oil-base Mud.
 - A. B. Winter: A New Application for the Neutron Log.

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 - V. J. Mercier: Radioactivity Well Logging in Kansas.

Some Recent Developments in Mud-analysis Logging

By B. OTTO PIXLER*

(Houston and Fort Worth Meetings, October 1945)

ABSTRACT

MUD-ANALYSIS logging provides identification of the fluid content of formations drilled by the rotary method and permits the accurate correlation of oil and gas shows with the depth. Mud-analysis logging eliminates much coring and has an especially important application in drilling programs when coring is particularly hazardous or the electric log is difficult to interpret correctly. An appreciation of the factors that influence the results of the mud analysis, such as rate of penetration, mud properties, coring, and characteristics of reservoir rock as related to the "flushing effect," permits a better understanding of the mud-analysis log.

Recent studies of the relationship of the two gas readings obtained by the gas-detector instrument have proved significant. The difference between the total combustible gas reading and the higher molecular weight gas reading indicates the presence of methane. With few exceptions, zones not showing an increase of methane probably can be condemned. Mud-analysis logging furnishes valuable information, which generally cannot be obtained by other methods.

INTRODUCTION

Logging by mud analysis of wells drilled with rotary tools is a direct method of locating oil-and-gas-bearing formations. The use of this method of logging has increased each year until now more than 20 field units are being used in 13 oil-producing states and in some foreign countries. Several papers¹⁻⁹ have been published in the petroleum trade journals describing in

detail the equipment and the application of mud-analysis logging. This paper will discuss briefly the method and review its application and some of the late developments.

METHOD

As the drilling of a well progresses, the drilling bit dislodges and disintegrates a cylindrical section of the formation. If oil or gas is contained in the pore spaces of the cylinder, some of the contents of these porous spaces will be entrained in the drilling fluid. In wall logging by mud analysis, the mud is continuously examined for oil and gas on its return to the surface, and the results are correlated back to the actual depth of the hole at the time the mud was clearing the eyes of the bit.

The test for gas is made by diverting a portion of the circulating mud from the flow line to a separator or gas trap, where the mud is thoroughly mixed with air and a portion of the gas entrained in the mud is removed. A stream of air is drawn counter-current to the flow of mud in the gas trap, thus materially assisting the separation of the gas from the mud. The air-gas mixture is then drawn into a "hot-wire" gas-detector instrument where the percentage of the combustible gas is determined.

The presence of oil in the formation drilled is detected by a physical examination of the drilling mud under ultraviolet light. A sample of the mud is treated to reduce the surface tension and gel strength, after which it is placed in a viewing box. This box is so constructed that all external light is excluded and so that the sample may be subjected selectively to either ultra-

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* Baroid Sales Division, National Lead Co., Houston, Texas.

¹ References are at the end of the paper.

violet or white light. All oils, refined or crude, fluoresce under the ultraviolet light. It is, therefore, often necessary to carefully study in the viewing box samples of all the various refined oils used on the rig.

tween these oils and the crude oil observed in the mud sample. The magnitudes of the oil "shows" in fluid logging units are based on the amounts of observed fluorescence of the crude oil.

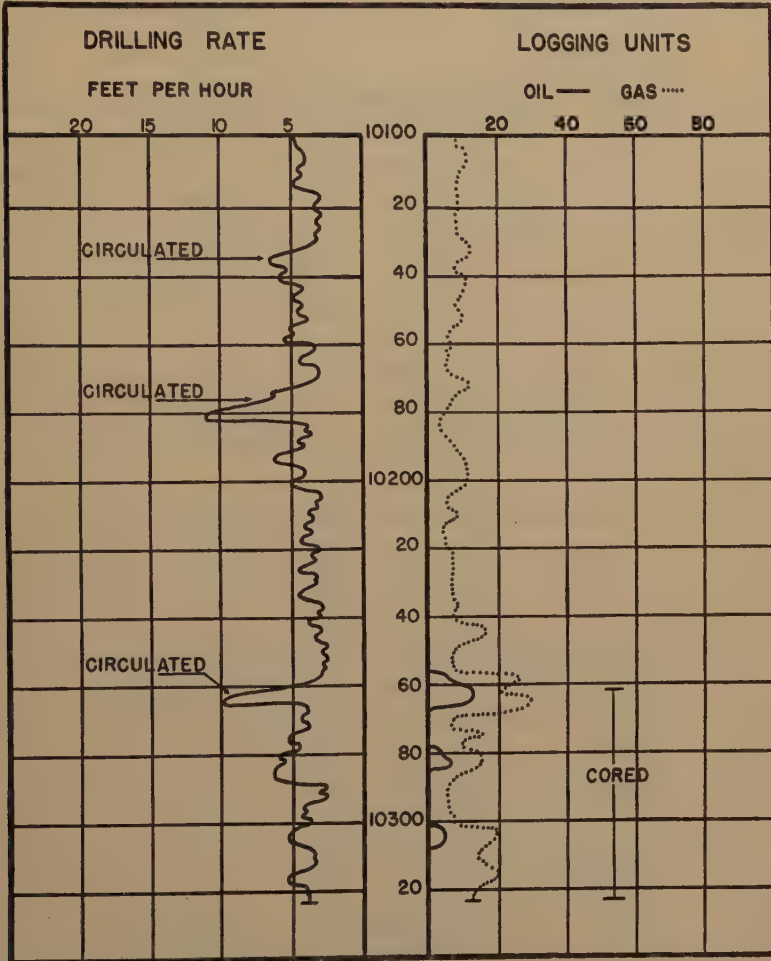


FIG. 1.—SECTION OF LOG ILLUSTRATING APPLICATION OF CONTROLLED CORING THROUGH MUD ANALYSIS ON A DEEP EOCENE WILCOX WELL.

Many crude oils will fluoresce in much the same way as refined oils under the ultraviolet light but when viewed under the white light differ in appearance. By recognizing the rig oils when examined under both the ultraviolet light and the white light, it is possible to distinguish be-

Additional instruments include a depth meter, pump-stroke counter and pump-rate meter. These provide the necessary data for obtaining a rate of penetration curve and for properly correlating with depth shows of oil and gas found in the mud sampled at the surface. Periodic checks

are made on the characteristics of the drilling mud, including the salinity of the mud. Significant increases in the salinity of the drilling mud indicate that salt or a

salt concentration of the drilling mud significantly, so this method cannot be depended upon to show all salt-water sands.

The log is prepared as a plot of the mag-

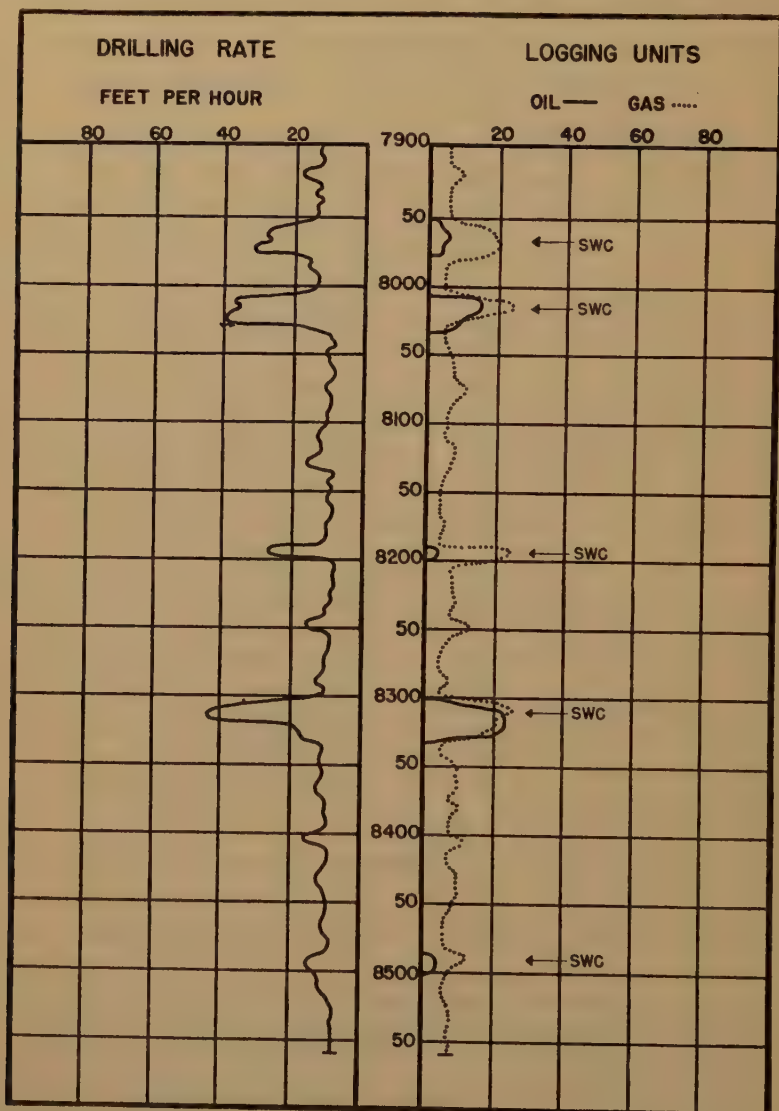


FIG. 2.—SECTION OF LOG ON A SOUTH LOUISIANA WELL DRILLED TO TOTAL DEPTH WITHOUT CORING. SIDE WALL CORING POINTS ARE INDICATED.

salt-water zone has been penetrated, but this method of locating salt-water sands is not entirely satisfactory. The drilling of salt-water sands may not increase the

nitude of the oil and gas shows versus depth and the rate of penetration versus depth. Drilling-mud characteristics and other pertinent well data are also included.

CORING TIME SAVED

On many wildcat wells, core barrels are run continuously for hundreds of feet in order to obtain cores of all possible productive horizons. On others, the operator will core every "drilling break" (significant increase in rate of penetration) that may indicate sands. Either program is costly and hazardous and many unnecessary cores are cut. When mud analysis is utilized as a control, coring is held to a minimum. The well may be drilled as rapidly as possible until a "drilling break" is encountered. Drilling is continued for a few feet, then halted until the mud returned from the "break" is pumped to the surface and analyzed. If oil or gas is present, a core is taken; if not, normal drilling is resumed. By coring only the sands that show oil or gas in the mud returns, all unnecessary coring is eliminated, with resultant reduction of hazards and expenses.

Fig. 1 represents a section of the log of a well drilled in the deep Eocene Wilcox of the Gulf Coast. It is typical of many such logs and illustrates the application of controlled coring. Drilling on this well was halted at 10,135 ft., at 10,176 ft., and at 10,261 ft. until the mud returns had been circulated to the surface and analyzed. Drilling was resumed at the two upper points when the mud-analysis results showed no oil or gas. However, at the lower point, oil and gas were detected, and as a result of this information the section was cored.

In one area, where several productive zones and numerous thin saturated sand stringers are encountered in the Eocene Wilcox, mud-analysis logging has been applied on about 75 per cent of the wells drilled to date. As mud analysis was not applied on the first wells drilled, an average of 150 cores per well were taken in the Wilcox. On one of the wells recently drilled, where mud analysis was used successfully as a coring control, it was necessary to take only 70 cores. This was a minimum

of coring and much information not previously available on the section was obtained, which greatly aided the testing of the well. In areas where the Wilcox does not contain these multiple showings, the saving in coring is relatively much greater.

In areas where the recovery of side-wall cores is good, the well may be drilled without coring to total depth and side-wall coring points picked from the mud-analysis log and other available information. For instance, Fig. 2 represents a section of a log on a South Louisiana well that was drilled without coring to total depth. Before the well was tested, side-wall cores were taken at 7965 ft., at 8015 ft., at 8195 ft., at 8310 ft. and at 8490 ft. Good indications of oil were obtained from side-wall cores at 8015 and 8310 ft. and a fair show was obtained from the side-wall core at 7965 ft. Oil was indicated only as fluorescence of the ether extract under ultraviolet light from the cores taken at 8195 and 8490 ft. Tests were made at 8302 to 8318 ft. and at 8008 to 8020 ft. The best results were obtained from the lower section where the well was completed at an initial potential of 125 bbl. of oil per day. This method of exploratory drilling without coring is particularly advantageous in areas where extreme pressures, sloughing shale, or other conditions, make coring exceptionally hazardous. In several cases, hole trouble developed to an extent that the usual electrical survey could not be made and the mud-analysis log was the principle source of information on the lower section of the hole.

IDENTIFICATION OF FLUID CONTENT

Mud-analysis logging has been widely used in areas where the interpretation of the electric log for fluid content of formations is uncertain or impossible. One such area is the Permian Basin of West Texas, where, because of salt water in the mud used in drilling, the electric log is of little value for the interpretation of fluid con-

tent. There, mud-analysis logging has been used extensively on both wildcat and field development wells. Of particular importance in development wells is the accurate location of the gas-oil contact. Fig. 3, a

of gas per 24 hr. The well was shot with 87 quarts of nitroglycerin from 4090 to 4115 ft. and, on potential tests, flowed 450 bbl. of oil per day with a gas-oil ratio of 1400 to 1.

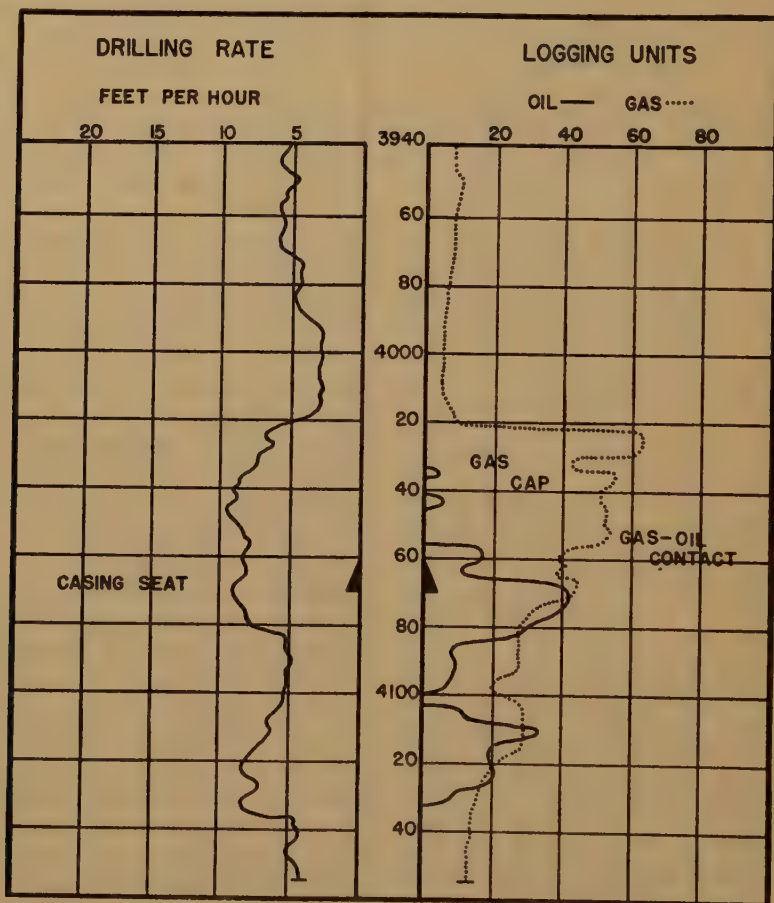


FIG. 3.—SECTION OF LOG OF A FIELD DEVELOPMENT WELL IN THE WEST TEXAS PERMIAN BASIN.

log of a development well in the Permian Basin, is an example of how operators have used the mud-analysis log for locating the gas-oil contact. The gas-oil contact is at 4056 ft. In this well, because of the thick section, the casing seat was selected at 4070 ft., well below the gas-oil contact, in order to reduce the danger of an expanding gas cap increasing the initial gas-oil ratio. The operator swabbed 30 bbl. of oil in 4 hr. with estimated 100,000 cu. ft.

The mud-analysis log has proved very useful in the Gulf Coast area, where the electric logs of the Eocene Wilcox section are difficult to interpret correctly for the fluid content of the formations. Figs. 4 and 5 are sections of composite logs comparing the electric and mud-analysis logs of the Eocene Wilcox in two widely separated areas. Fig. 4 is representative of the results obtained in the deep Wilcox and illustrates the difficulty of interpreting the electric

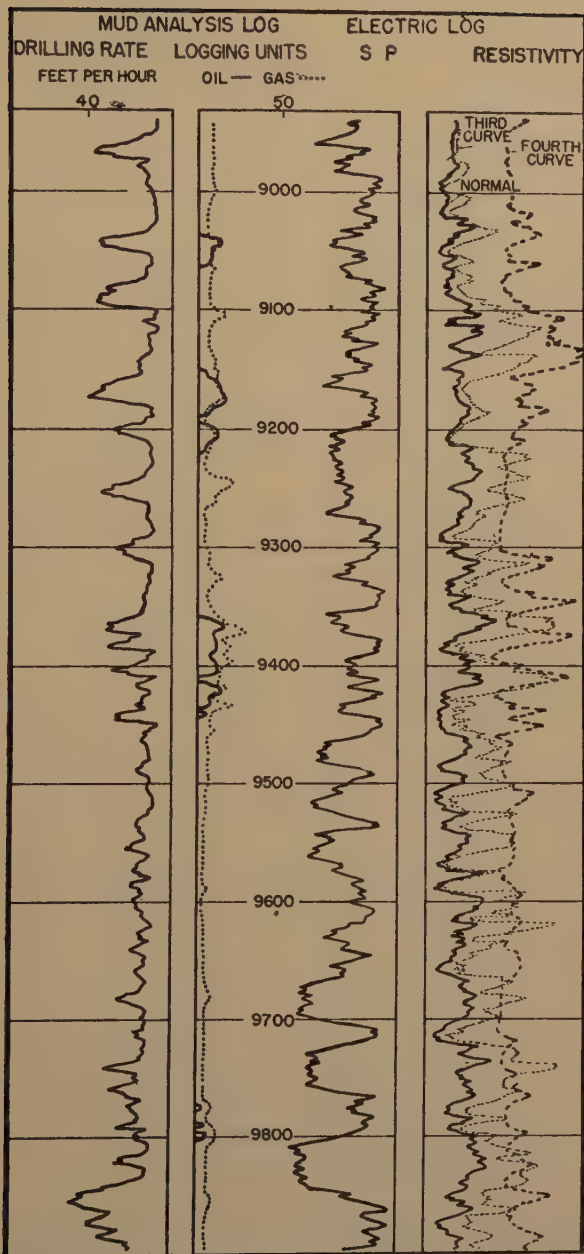


FIG. 4.—COMPOSITE LOG OF PART OF ELECTRIC AND MUD-ANALYSIS LOG OF A DEEP EOCENE WILCOX WELL.

log. With the aid of positive identification of the fluid content of the sand bodies by means of mud analysis, testing is reduced to a minimum, with a resultant decrease in time and money expended on the completion of the well.

Fig. 5 is typical of the results obtained in the shallow Wilcox and illustrates how an incorrect interpretation of the electric log could cause a commercial oil and gas possibility to be overlooked. The mud-analysis results alone have accounted for the discovery of several commercial sands of the Eocene Wilcox.

FACTORS AFFECTING INTERPRETATION

Factors that affect the interpretation of the mud-analysis log are: the rate of penetration, mud properties, coring, and the reservoir characteristics. The effect of these various factors on the interpretation of the oil and gas shows can be developed from a discussion of the action of the drilling bit as drilling progresses. Normally, the drilling mud exerts a pressure greater than that of the fluids in the formation and the pressure tends to force mud back into the permeable formations. Normally, the mud solids cannot penetrate the formations and are deposited on the face of the permeable formations as a filter cake. As this filter cake is being deposited, water from the mud enters the formation. As the drilling bit rotates on the bottom of the hole, it continuously removes the filter cake deposited on the bottom of the hole and exposes fresh formation. Studies of the filtration process have shown that the rate of filtration is proportional to the inverse of the square root of time.¹⁰⁻¹¹ While permeable formations are being drilled, there is a continual advance of mud filtrate ahead of the bit. This mud filtrate flushes a portion of the fluids contained in the reservoir rock radially back into the formation. The relative intensities of the oil and gas shows are decreased as a consequence of this flushing. The amount of water in-

filtration varies with the permeability of the formation and the "water loss" of the mud. Fortunately, this flushing action is far from complete except in unusual cases of highly permeable formations and "high-water-loss" muds.

In general, a permeable formation drills rapidly, and with each bite of the drilling bit a relatively large section of the formation is cut away. Consequently, the drilling bit keeps up with the advance of water, allowing little flushing action to occur. In dense formations, even when the drilling is very slow, the rate of initial filtration is small and the gas and oil shows are not reduced appreciably by the flushing action. As soon as the initial stage of filtration has passed, the rate of filtration is not dependent upon the permeability of the formation but rather upon the permeability of the filter cake deposited from the drilling mud. Where comparable data are available, better oil and gas shows have been obtained where lower water-loss muds are used.

Other mud characteristics do not seriously affect the mud-analysis results unless viscosity and gel strength are extremely high, in which case the gas tends to stay in the mud and recirculate through the hole. The best logging results are obtained under normal drilling conditions when hole is being made as rapidly as possible. And if, for example, while straightening a hole, light weight is carried on the bit, reducing the drilling rate, the magnitude of oil and gas shows may be reduced. Cores usually are taken at reduced drilling rates, and coring reduces the volume of the formation and its fluids entering the mud; both factors tend to reduce the relative intensities of oil and gas shows.

Usual fluid reservoir pressures provide good logging conditions when the formations are drilled at rates limited only by the drilling equipment and the hardness of the reservoir rock. However, unusually high or low fluid reservoir pressures affect the in-

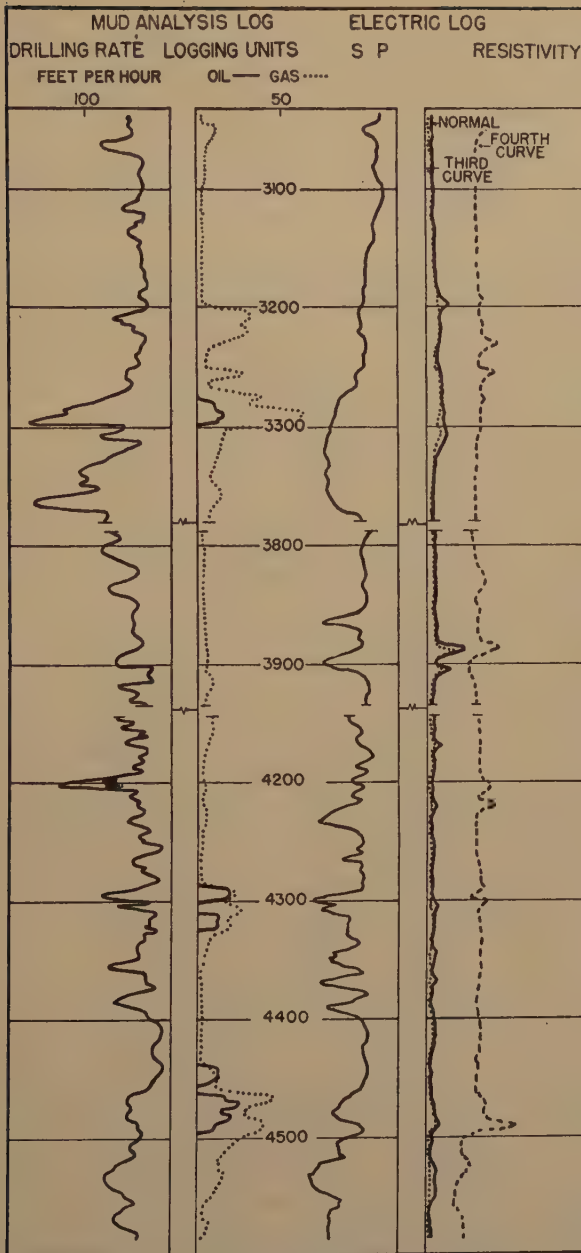


FIG. 5.—COMPOSITE LOG OF PART OF ELECTRIC AND MUD-ANALYSIS LOG OF A SHALLOW EOCENE WILCOX WELL.

terpretation of the mud-analysis log, in that under some circumstances the intensities of oil and gas shows may not be indicative of the actual reservoir fluid content.

breaks, to determine the advisability of coring. Without a significant increase of drilling rate, the mud analysis suddenly showed extremely large concentrations of oil and gas. Drilling was halted and as the

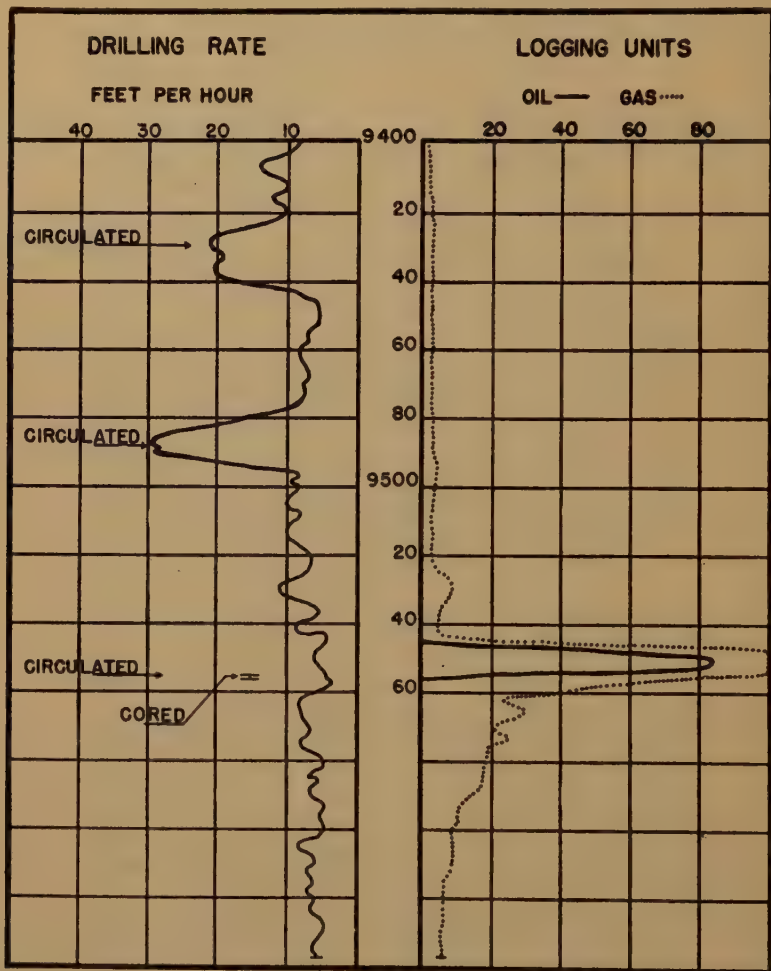


FIG. 6.—SECTION OF LOG OF TEXAS GULF COAST WELL ILLUSTRATING RESULTS OF MUD ANALYSIS LOGGING FROM VERY TIGHT SAND UNDER ABNORMALLY HIGH FLUID PRESSURE.

Such a condition is illustrated in Fig. 6, which shows part of a log of a well in the Texas Gulf Coast area. Other wells in this area had penetrated sands that were drilled at rates comparable to shales. Accordingly, instructions were given to halt drilling on shows of oil or gas, as well as on the drilling

shows continued throughout the circulating period, a core was taken. The core recovered was a tight, fine-grained sandstone saturated with oil. Subsequent tests showed the sand to be nonproductive. It seems probable that the large intensities of oil and gas shows resulted from a release of the

fluids held under abnormal pressure in the tight sand.

Under normal drilling conditions, the effect of flushing action on the mud-

gas increase. Drilling was halted and a drill stem test was attempted. Because the packer failed, the operator ordered a core at a reduced hole size. The mud analysis

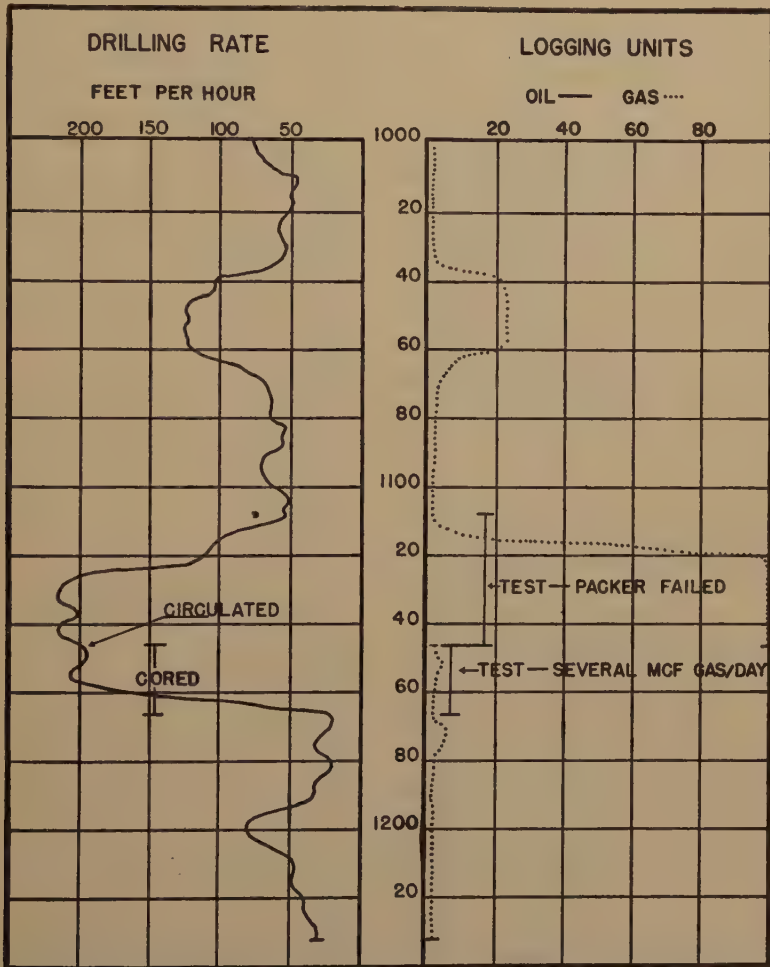


FIG. 7.—SECTION OF LOG OF CALIFORNIA WELL ILLUSTRATING RESULTS ON MUD-ANALYSIS LOG OF UNUSUAL CASE OF FLUSHING ACTION.

analysis log is not critical. However, there are unusual conditions under which the showings of gas and oil are reduced appreciably by flushing action. Fig. 7 is part of a mud-analysis log that illustrates an unusual case of flushing action in a California well. An analysis of the mud returns from a drilling break showed a significant

showed little or no gas in the cored section; however, a test was made in the reduced hole, and several million cubic feet per day of gas was obtained with the bottom-hole pressure considerably lower than the pressure exerted by the hydrostatic head of the mud column. Between the time the sand was first encountered and the time it was

cored, the sand face was exposed to the static mud column for 60 hr. The water loss of the mud was, A.P.I., 40 c.c., and as the sand was very porous and permeable, it is reasonable to conclude that a flushing action had occurred in the bottom of the well radially outward and downward to such an extent that it materially affected the mud-analysis results while coring.

This same condition has occurred also in the Gulf Coast area. On one well in Louisiana, there was a serious loss of returns when the bit penetrated a particular porous and permeable sand section. Drilling proceeded at a slow rate while the formation continued to take some of the mud. An analysis of the mud that did return to the surface indicated neither gas nor oil, while subsequent tests of the sand showed commercial gas possibilities under fairly low pressure.

Flushing action that affected the mud logging results in a similar way occurred on another California well. The operator believed that a drilling rate of 20 ft. per hour was the ideal rate of penetration for the best logging results. Sands were encountered and drilled at 20 ft. per hour which normally would have drilled 100 ft. per hour or more. Relative values of shows in gas-bearing sands were not indicative of actual reservoir conditions. At the comparatively slow rate of penetration, flushing occurred in all of the loosely consolidated sands and the amount of flushing varied with the effective porosity and permeability.

ESTIMATION OF METHANE

The gas-detector instrument has been provided with a means of changing the temperature of the gas-detector filament. At the normal operating temperature, the instrument indicates the total combustible gas in the air-gas mixture being tested. At a lower temperature, the instrument indicates only the hydrocarbons of higher molecular weight and does not indicate methane. Methane gas is indicated by the difference

between the readings for total combustible gas reading and the higher hydrocarbon gas. Through a study of past results, the significance of the relationship existing between the two gas curves has materially assisted field interpretations. With few exceptions, all productive horizons logged by the mud-analysis method have shown a definite increase of methane gas. Where the readings for the higher hydrocarbon gas are equivalent to or slightly less than those for the total combustible gas, methane is not indicated. Such gas shows can probably be condemned as originating in a poor or nonproductive horizon, as occurring in shale, or as gas recirculated by the mud.

Fig. 8, a section of a log on a well drilled in eastern Louisiana, is representative of results obtained with the total combustible and methane-gas readings. The curve for total combustible gas indicates three significant gas increases between 10,200 and 10,400 ft.; however, the curve for methane gas does not show any increase between those depths. The electric log indicates rather poor sand sections corresponding to the upper two gas shows, and at the lower gas increase the electric log indicates a shale section. The most important gas increases occur just below 10,600 ft. and at 10,700 ft. Significant increases in methane gas are encountered along with a showing of oil. The electric log also indicates that the sections are favorable for testing. Tests were made at 10,617 to 10,633 ft.; 10,688 to 10,690 ft.; and at 10,702 to 10,710 ft. All of the tests recovered oil and gas and a dual completion was made in the two sections with an initial flow of 173 bbl. of oil per day.

Because of the several factors that influence the size of the shows, at its present state of development, mud-analysis logging does not give quantitative results as to the amount of oil and gas occurring in a formation; nor does it furnish quantitative information on the productivity of the oil and

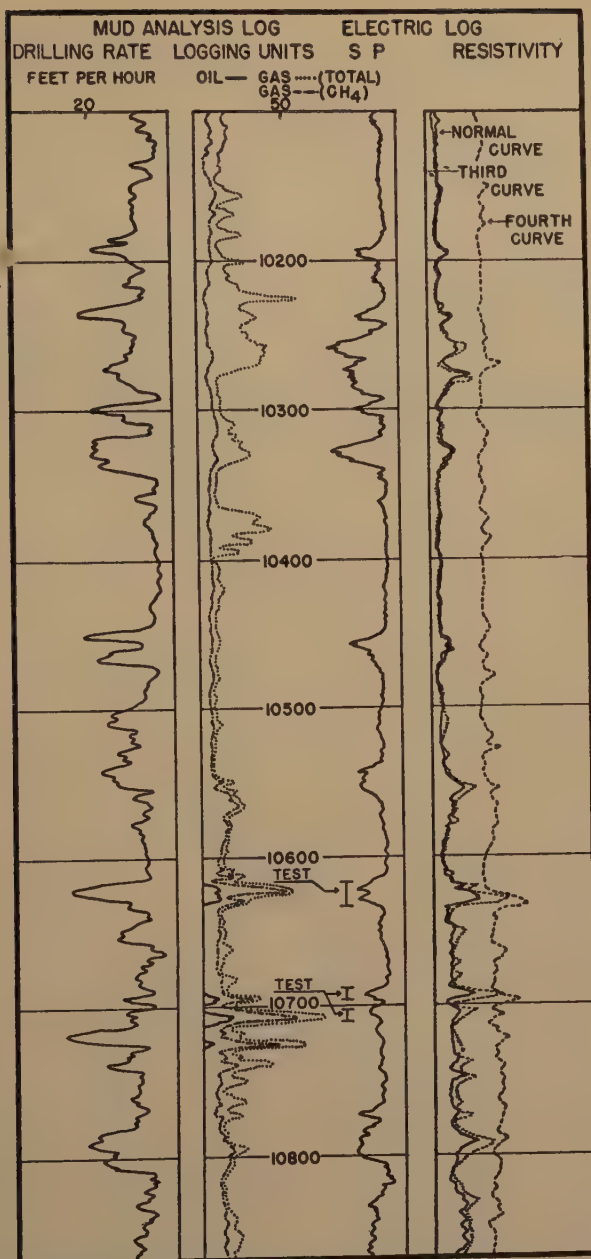


FIG. 8.—SECTION OF ELECTRIC AND MUD-ANALYSIS LOG ON WELL DRILLED IN EASTERN LOUISIANA, WHICH REPRESENTS RESULTS OBTAINED WITH TOTAL COMBUSTIBLE AND METHANE-GAS READINGS.

gas horizons. This logging method does give reliable qualitative information on the occurrence of oil and gas, and, as mentioned above, this information is extremely valuable in wildcatting operations and in many field-development programs when the information cannot be obtained more economically by other methods.

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A Method for Determining Fluid Movement in Wells

BY SHERMAN L. PEASE*

(Los Angeles Meeting, October 1944)

ABSTRACT

An inexpensive and relatively rapid method that can be used by field crews is described. Fluid movement is determined by releasing a tracer (dye) in the well at a predetermined level and, after an interval of time, sampling the well fluid at another level. The testing equipment consists of a combined crusher and sampler unit that is run into the well on a wire line. The rate of movement can be calculated from time-volume relationships.

DESCRIPTION OF METHOD

It is often desirable to determine whether there is occurring any transfer of fluid from point to point in a shut-in well, and, if so, to measure the rate of movement.

When it is desired to examine a large number of wells for possible "thief" sands, the time and expense will be considerable unless the method used is inexpensive and rapid. After experimentation with several possible solutions to the problem, the Production Department of the Shell Oil Co., Inc., developed the apparatus described herein, which has proved satisfactory. Routine operations with it can be carried out by field production crews with a minimum of technical supervision and with negligible investment in equipment.

The method is based upon releasing a suitable tracer in the well fluid at a known level, and recovering a sample of well fluid at another level after a measured interval of time. Repetition of this process with different time intervals between release and sampling gives the necessary data.

For purposes of illustration, the setup for measuring migration of fluid in an upward direction is described in the following paragraphs.

The arrangement of equipment is shown diagrammatically on Fig. 1. The elements of the combination unit are the tailpiece, the crushing device, the spacer and the sampling device. The lengths of the tailpiece and spacer are varied to place the crushing and sampling devices in the desired positions in relation to the sands being tested. The crushing device breaks the glass bottle containing the tracer when the tailpiece strikes the bottom of the well and the tension on the sand line is slackened. Because of the open construction of the crushing device, the tracer is quickly and completely disseminated in the well fluid. The sampling device is a suction bailer, which obtains a sample of the fluid surrounding the perforated nipple just before the unit is picked up off bottom. The sample is retained in the barrel by the ball valve for examination at the surface.

Normally, on the first run into a well, the sample is obtained near the releasing point of the tracer, and thereafter samples are taken near the base of the upper sand if migration is indicated by the dilution or absence of the tracer in the initial sample. The length of the time interval between the releasing of the tracer and the sampling of the well fluid is varied for successive runs, attempting first to establish the rate within limits and then to define it more accurately by additional runs if necessary.

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* Shell Oil Co., Inc., San Francisco, California.

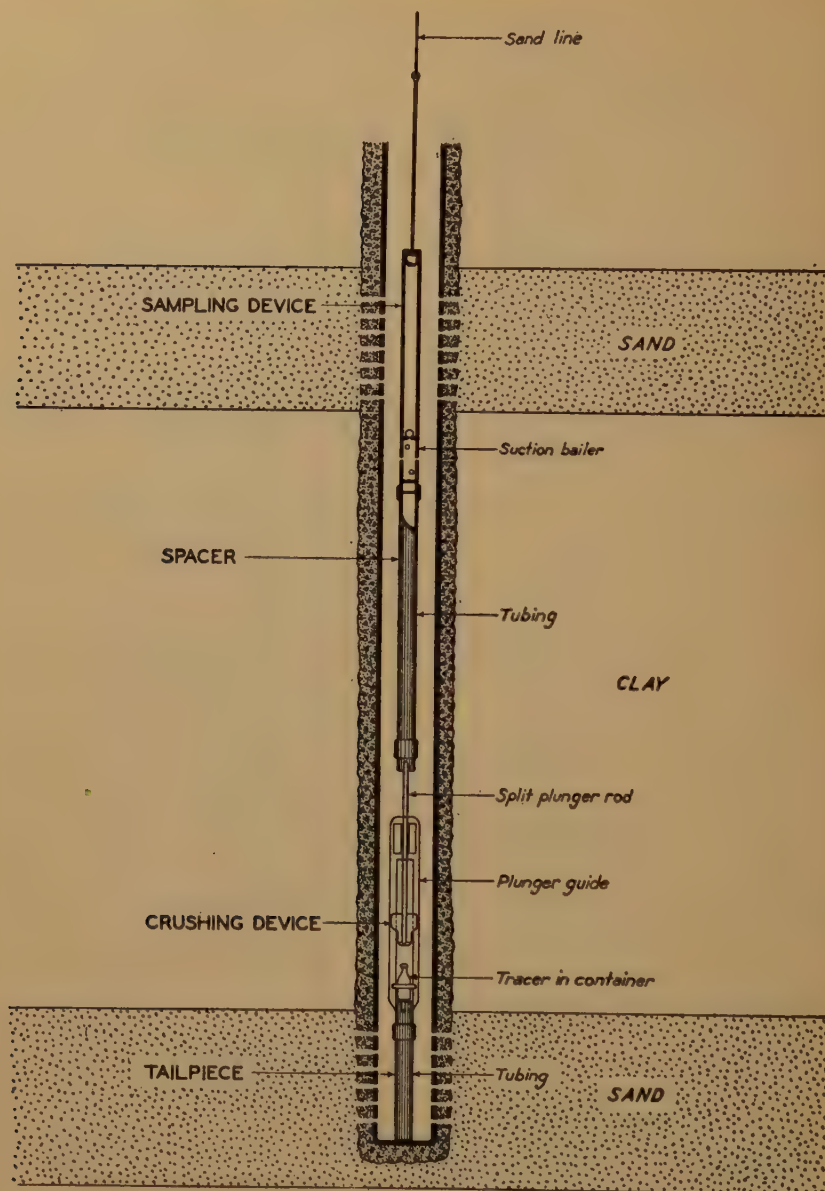


FIG. 1.—EQUIPMENT FOR DETERMINING FLUID MOVEMENT.

The rate of migration can be calculated from the relationship of the time interval to the volume represented in the interval between the releasing and sampling points. It is the writer's opinion, based on field results, that approximate rates of fluid movement in 6 $\frac{3}{8}$ -in. casing from less than 100 to more than 1000 bbl. per day can be determined by the method herein described.

For the tracing material, solutions of brilliant water-soluble aniline dyes have been found satisfactory in wells having an appreciable water cut. Laboratory experiments have indicated that the dyes can be identified in fluids having a water cut as low as 10 per cent. The use of a series of contrasting dyes for successive runs serves to identify each run and to eliminate confusion. The average cost of the dye solution is less than one dollar per well.

Possible factors influencing the accuracy of the results are the diffusion of the dye solution through the well fluid, the stirring action of eddy currents set up by the testing unit as it is lowered to bottom, and the movement of fluid outside the casing. Laboratory tests with the dye solutions used have indicated that no appreciable diffusion in an upward direction ahead of the true color front occurs within the time intervals normally used. This is further substantiated by field tests in which the sharp break from a colorless sample to a strongly colored sample occurs within a time interval representing the movement of about one barrel of fluid. To reduce eddy currents as much as possible, the unit is lowered through the intervals to be tested at a very slow rate, and is held just off bottom several minutes to allow any currents to subside before the bottle is broken.

POSSIBLE VARIATIONS AND APPLICATIONS

It will be appreciated that the general method has many possible variations with respect to equipment, technique and trac-

ing materials, depending upon the objectives in mind and the accuracy required. By obtaining multiple samples, the determination of a migration rate could be accomplished with fewer runs; short bailers in tandem, or multiple-port bailers constructed so as to take independent samples simultaneously over a considerable interval could be used. The unit illustrated on Fig. 1 is run into the well on a sand line, but smaller units might be adapted for use with a measuring line (piano wire) outfit. With minor changes, the equipment can be used for determining downward movement as well as upward movement of fluid in a well bore. By utilizing suitable tracing materials, the method might be used for determining the rate of the migration of oil into a gas cap or depleted zone.

ACKNOWLEDGMENT

This description of the method of determining fluid movement in oil sands is published by permission of the Shell Oil Co., Incorporated.

DISCUSSION

N. VAN WINGEN.*—The method discussed in this paper appears to offer some interesting possibilities for the tracing of interzonal fluid movements. I should like to ask the author:

1. Has any attempt been made to correlate the results obtained in this manner with indications from thermometric surveys, and if so how well do the results of the two methods check?

2. In a thick producing section, would it be possible to readily adapt the instrument so that the bottle can be broken without the necessity of touching bottom?

3. Has this method ever been used in high-pressure wells using a single-strand wire and stuffing box?

4. Has a suitable oil-soluble tracer been found, and has this method been applied to determine clean oil migration.

5. Could the author give some further information regarding the method by which the

* Richfield Oil Corporation, Los Angeles, California.

time interval between breaking the bottle and sampling is established?

6. How serious is the factor of diffusion when the fluid migration is downward?

S. L. PEASE (author's reply).—My replies to Mr. van Wingen follow the order of his questions:

1. Thermometric surveys have not been made in wells in which this method has been used.

2. Although the testing equipment has not yet been adapted for this particular problem, it appears mechanically feasible to break the bottle without touching bottom; for example, by incorporating in the crushing device a suitable means of contacting the inside of the casing.

3. This method has not been used in wells in which pressures were sufficient to necessitate the lubricating equipment mentioned.

4. Use of an oil-soluble tracer was suggested in the paper for determining the rate of migration of clean oil; laboratory and field tests, however, have been limited to the investigation and use of water-soluble tracers in fluids containing some water.

5. The length of the time interval (between releasing the tracer and sampling) to be used on the first run into a particular well is based on previous field testing experience in the area as well as on the production characteristics of the well. The length of the time interval for each subsequent run is contingent upon the results obtained in the preceding run, the practice being to "bracket" the rate within limits and subsequently to define it more accurately as required.

6. Tests have indicated that the factor of diffusion is relatively unimportant unless the movement of fluid in the casing is extremely slow.

Chapter III. Refining

Review of Refinery Engineering for 1945*

BY WALTER MILLER,† MEMBER A.I.M.E.

By the beginning of 1945 the output of petroleum products for war had reached a volume and a rate of growth which practically assured all requirements so long as war continued.

The programs for making gasoline, lubricating oils of required quality, toluene for T.N.T., and chemicals for manufacture of synthetic rubber, as well as numerous other lesser petroleum products, were all well in hand, and unless catastrophic developments occurred there was no doubt of the ability of the industry to meet all demands. The end of the fighting found the refining industry working at top capacity on war commodities, but also in position to convert quickly into peacetime civilian production.

100-OCTANE AVIATION GASOLINE

Production of the vital 100-octane aviation gasoline, starting with approximately 44,000 bbl. daily capacity at our entry into the war, reached a top of 525,000 bbl. a day in the United States by the end of hostilities. With 75,000 bbl. from other Allied sources, the grand total was 600,000 bbl., or 25,000,000 gal. each 24 hr. available to the armed forces had fighting continued. At times it was a close race between requirements and production, but never were any important military operations involving the use of high-octane aviation gasoline held up or delayed for lack of sufficient

output of such material. The undivided effort of the entire refining industry in full cooperation with the Government made this record possible.

Little diminution in output followed the German surrender on May 7. Plans called for a correspondingly greater activity for the Japanese war and possibly for well into 1946. But when the Japanese sued for peace on Aug. 10 most contracts were quickly canceled.

Substantial stocks, reputed to be somewhere between 20,000,000 to 30,000,000 bbl., built up largely between V-E and V-J day pending organization of the larger Japanese war program envisaged after Germany gave up, were in the Government's hands in this country, in addition to working stocks in the war areas.

TOLUENE AND LUBRICATING OIL

Requirements for toluene for T.N.T. increased rapidly as bombing speeded up with increasing control of the air by the Allies in Europe and Asia. Production in excess of T.N.T. requirements which had been going into 100-octane aviation fuel blending during 1943 and 1944 was again drawn into explosive manufacture early in 1945. In anticipation of the war continuing into 1946, two new plants were ordered constructed, the decision being announced in April, plans calling for one of them to get into production about the end of 1945, the other in the first quarter of 1946. Both of these projects were later canceled as victory made it evident that the additional supplies would not be needed. Production was

* Reprinted from *Mining and Metallurgy*, February 1946.

† Vice-President, Continental Oil Co., Ponca City, Oklahoma. Chairman, Committee on Refinery Engineering, Petroleum Division, A.I.M.E.

largely stopped with the ending of war activities. Total output had been at a rate of about 250,000,000 gal. a year throughout 1943 to 1945, compared with something of the order of 20,000,000 gal. prewar output.

No supply problem as regards lubricating oil was involved during the last war year. The rate of production of war-quality materials was sufficient to supply all needs easily with a satisfactory surplus to keep up with nonwar requirements.

SYNTHETIC RUBBER FROM PETROLEUM

Increasing efficiency and output of petroleum chemicals for synthetic rubber production made for a constant improvement in that situation to the end of the war. Output of the tire-making plants was also stepped up, with ample raw materials for the available capacity.

An interview in early December, given out by the associate director of the Office of Rubber Reserve, announced that butadiene from grain alcohol was being discontinued, although the plants would be kept in "stand-by condition" in case of emergency. "Our cost of butadiene this year," the associate director stated, "was about forty cents a pound from alcohol, compared with eight to ten cents a pound from petroleum. That made the cost of alcohol synthetic rubber around 24½ cents a pound, compared with 12 or 13-cent rubber from the petroleum butadiene plants on the Gulf Coast."

Lifting of rationing restrictions on tires Jan. 1, 1946, while not ensuring immediate unlimited availability of tires, indicates a rapidly approaching ability to take care of all needs, proving another petroleum industry war assignment handled to a satisfactory conclusion.

TRANSITION TO CIVILIAN PRODUCTION

The petroleum-refining industry is in a comparatively advantageous situation as to transition to civilian production. An

ample supply of crude oil and other raw materials such as casinghead gasoline and butanes is available. More than sufficient over-all refining capacity is ready to run all the crude oil required for any indicated civilian consumption of gasoline, lubricating oils, and raw materials such as butadiene for postwar production of synthetic rubber.

Most of the catalytic cracking installations were almost instantly convertible to motor gasoline production at higher rates per day. All but a small number of the units erected for war needs of 100-octane aviation fuel were so located as to coordinate easily with the regular operations of the refineries of which they formed a part. No major changes in lubricating-oil war products' plants are necessary. Taken as a whole, the transition to peacetime civilian operations of most wartime refining equipment is comparatively simple and involves no great expenditures or interruption of production. True, a number of the isomerization and alkylation units installed because of war necessity will not fit the economics of civilian motor gasoline production but in many instances the installations in the larger refineries will operate for increasing the quantity of motor gasoline components and raising the average octane value at not too high a cost.

POSTWAR GASOLINE QUALITY AND CATALYTIC CRACKING

The trend is definitely and strongly to higher-octane motor gasoline. The country-wide quarterly gasoline survey for the fall of 1945 shows between five and six octant numbers higher quality than in the war period of a year ago. This survey also discloses the quality of the present gasoline to average about one octane higher than in the last countrywide prewar survey, made in 1941, the latter having shown the highest octanes of the prewar period. The rise in octane is not uniform but indicates, as might be expected, that those districts more fully equipped with catalytic cracking

units are forging ahead in their octane quality faster than other sections.

Between 50 and 60 refineries, aggregating about 60 per cent of the industry's crude charging operations, have catalytic crackers, although not all of these are fully balanced in that respect.

Unquestionably this trend for higher-octane gasoline will continue further. Most of the larger refineries in the country, with crude-oil charging capacity from 25,000 bbl. per day up, have catalytic cracking units of standard sizes, with average investment and operating costs suitable for the scale of their operation. The smaller refineries not equipped with catalytic cracking face a serious problem because of the much greater investment cost per barrel of capacity and higher operating costs per unit of output. Considerable work has been and is being done in designing smaller units for refineries with crude charging rates down to 7500 bbl. per day, but for still smaller plants the outlook for catalytic cracking is discouraging and the necessarily small installations may carry a prohibitive expense.

A contract has been entered into by one small refiner for a 3000-bbl. catalytic unit, sufficient for a 7500-bbl. daily crude-oil operation, in which the investment cost will not be too excessive. This has been attained by simplification of design and utilization in part of other equipment which will be freed from thermal cracking units replaced by the catalytic crackers.

Unless a solution not now in sight for refineries of less than about 7500 bbl. of crude oil per day is evolved, such plants may be relegated to production of secondary grades of gasoline at lower prices, for which some market will always exist, and of products such as cleaning naphthas, solvent naphthas of various kinds, and special diesel fuels and furnace oils.

LUBRICATING OILS

Because of construction material and labor limitations during the past four years

many engineered projects for solvent-treating installations looking to improved quality of lubricating oil in existing output as well as a greater quantity of new production were held up by the War Production Board on the grounds, since proved justified, that existing plants were capable of supplying all the indicated critical needs for war purposes as well as important civilian needs.

A number of such projects have been reinstated in the last four months of the year, and other similar plans are under consideration. The continuing trend to higher temperatures and pressures in all internal-combustion engines and higher speeds in industrial machinery forces the manufacture of higher-quality lubricating oils. Solvent treating is one of the available means; already in fairly wide use, its adoption will follow quickly on a much larger scale.

For further increase in lubricating effectiveness much progress in the use of additives and essences in improved forms was made under the stress of war, and the trend to wider and more specific application of such beneficial ingredients will continue. Through increasing stability and oiliness, better lubrication of machinery by decreasing wear and corrosion, enabling more efficient operation of machines and motors will be possible. The raw materials so used are generally made available to oil manufacturers and users, following a practice of long standing, by the inventors and purveyors. In this sense the smaller refiner is not at a disadvantage.

HOUSE-HEATING AND INDUSTRIAL FUELS

Catalytic cracking definitely decreases production of residual heavy industrial fuel oils and increases distillate fuel oils in form suitable for domestic and light industrial heating purposes, and the effect will become greater as catalytic cracking operations increase. This is economically advantageous to the refiner, trending as it does to lesser output of his lowest price

product, heavy residual fuel, and increasing his production, although to a lesser degree, of the higher priced domestic heating oils. Such a trend also harmonizes with the constantly increasing use of domestic heating fuels, fully expected to continue, and although the supply of heavy fuel oils will be reduced, coal is available and can be substituted in the least important heavy industrial uses.

RESEARCH AND DEVELOPMENT

The Bureau of Mines is actively continuing its plans for developing information regarding sources of liquid petroleum products in the future from coal, oil shale, tar sands, and natural gas, under the plan authorized in 1944 by Congress, carrying a \$30,000,000 authorization for the program. Locations for experimental plants have been selected by the Bureau, including a new experimental laboratory near Pittsburgh. Announcement was made that a now idle Government-owned war plant, a \$17,000,000 installation for synthetic ammonia near Louisiana, Mo., would be utilized by the Bureau in its work under this program.

Much technical information obtained in Germany is currently being made available to our industry in respect to research and developments carried on in that country for the last six to eight years but not disclosed previously. This is being studied and analyzed by refiners and technologists in our country. While not yet susceptible to accurate appraisalment as to value to the United States, hopes are not too high from the viewpoint of commercial application. German development has been conducted in an entirely different economic atmosphere, because of the generally higher petroleum products price level prevailing in that country, the comparative scarcity of petroleum raw materials, and the disregard of costs involved in the long-time war economy.

Information from Germany on the later Fischer-Tropsch synthetic oil-making proc-

ess does not change materially the commercial picture that has governed the studies and plans looking to its use in the United States with natural gas as the starting raw material. As yet no commercial installation has been started here, although such a move is under active study and contemplation. If commercially feasible, it would be a logical step so far as raw-material supply is concerned because the latest estimate of natural gas reserves by a competent authority is 140 trillion cubic feet, some 25 trillion cubic feet higher than estimates of a year or more ago, with the discovery of still more reserves expected. The apparent margin of profit from operation is, however, not considered in some quarters to be as high as desirable for such a new venture, and the time of actual large-scale commercial application may well depend on the future price of motor gasoline.

Several refining companies have announced new and extended research and development facilities, and all indications are that such activities will be greatly increased and broadened. Not much has been given out as to actual proved accomplishments outside the war effort during 1945, but the new activities, based as they will be on the general cooperative work carried on during the war years, augur well for progress that should carry the chemical and technical fields of petroleum refining far beyond their present bounds. The fine foundation built for cooperative scientific work during the war years under the auspices of the Petroleum Industry War Council and Petroleum Administration for War, actively carried out by the Technical Advisory Committee and the Aviation Gasoline Advisory Committee of P.I.W.C., plus the accomplishments of the Toluene Technical Committee working in collaboration with the Ordnance Division of the War Department, make a great exhibit in favor of continuing much of such cooperative work for greater future industry progress.

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